B O N N E V I L L E P O W E R A D M I N I S T R A T I O N

2007 Wholesale Power Rate Case Initial Proposal

Direct Testimony

Book 3

November 2005

BPA Exhibit No.	Witness
WP-07-E-BPA-19	Wedlund, Hirsch, Klippstein, Wagner
WP-07-E-BPA-20	Bermejo, Berdhal, Murphy, Bolden, Homenick
WP-07-E-BPA-21	Berdahl, Gilman, Homenick
WP-07-E-BPA-22	Pompel, Wiley
WP-07-E-BPA-23	Lee, Bolden, Homenick, Keep, Hairston, Klippstein, Konesky
WP-07-E-BPA-24	Pyrch, Meadows, Johnson, Keating, Malin, Ingram
WP-07-E-BPA-25	Ingram, Malin, Mainzer
WP-07-E-BPA-26	Mainzer, Bolden, Miller, McLeod
WP-07-E-BPA-27	Keep, Doubleday, Brodie, Mace

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WP-07-E-BPA-14	Risk Mitigation Testimony	Michael R. Normandeau, Byrne E. Lovell, Arnold L. Wagner, Sid Conger, Jr., Alexander Lennox
WP-07-E-BPA-15	Cost of Service Analysis and Rate Design Changes and Adjustments	William J. Doubleday, Byron G. Keep, Paul A. Brodie, Ronald J. Homenick
WP-07-E-BPA-16	Residential Exchange Average System Cost and Load Forecasts	Rodney E. Boling, William J. Doubleday, Paul W. T. McClain
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TESTIMONY OF

SPENCER G. WEDLUND, JON A. HIRSCH, JANET ROSS KLIPPSTEIN,

AND ARNOLD L. WAGNER

Witnesses for Bonneville Power Administration

SUBJECT: REVENUE AND PURCHASED POWER EXPENSES FORECAST

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TESTIMONY OF

SPENCER G. WEDLUND, JON A. HIRSCH, JANET ROSS KLIPPSTEIN,

AND ARNOLD L. WAGNER

Witnesses for Bonneville Power Administration

SUBJECT: REVENUE AND PURCHASED POWER EXPENSE FORECAST

Section 1. Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Spencer G. Wedlund and my qualifications are contained in WP-07-Q-BPA-51.

A. My name is Jon A. Hirsch and my qualifications are contained in WP-07-Q-BPA-16.

A. My name is Janet Ross Klippstein and my qualifications are contained in WP-07-Q-BPA-25.

A. My name is Arnold L. Wagner and my qualifications are contained in WP-07-Q-BPA-50.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to describe the process used to prepare Bonneville Power Administration's (BPA) revenue forecast and to sponsor BPA's revenue forecast contained in Chapter 5 of the Wholesale Power Rate Development Study (WPRDS), WP-07-E-BPA-05, and to sponsor Section 3 of the Documentation for the WPRDS, WP-07-E-BPA-05A.

Q. How is your testimony organized?

A. Our testimony contains ten sections, including this introductory section. The second section summarizes BPA's revenue forecast. The third section describes changes to the revenue forecast since BPA's May 2000 final power rate proposal. The fourth section describes BPA's forecast of revenues from Subscription products. The fifth section describes BPA's forecast of revenues from long-term contracts. The sixth section describes BPA's forecast of revenue from short-term surplus sales. The seventh section describes BPA's sales of ancillary and reserve services. The eighth section describes BPA's forecast of Treasury credits. The ninth section describes BPA's other revenues. And the tenth section describes BPA's forecast of balancing power purchases and the associated purchased power expense.

Section 2. Revenue Forecast Purpose

Q. What is the purpose of the revenue forecast?

A. The revenue forecast documents the revenue BPA expects to receive during the rate period, given a specified set of rates. Two revenue forecasts were prepared for this proposal: revenue from current rates and revenue from proposed rates.

Q. What is the purpose of the current rate revenue forecast?

A. The current rate revenue forecast documents the revenue BPA expects during fiscal years (FY) 2005 through FY 2009, using the rates that were effective April 1, 2005 (for the remainder of FY 2005); for FY 2006 the rates that were effective on October 1, 2005; and for FYs 2007-2009 the rates that were posted in May 2000. Pursuant to U.S. Department of Energy Order RA6120.2, the current revenue forecast is used to test whether the revenue from existing rates satisfies BPA's revenue requirement.

Q. What is the purpose of the proposed rate revenue forecast?

A. The proposed rate revenue forecast documents the revenue BPA expects from sales over the rate period (FY 2007-2009) from the proposed rates. This forecast is used to demonstrate that the revenue from proposed rates enables BPA to meet its revenue requirement.

Q. What revenues are projected for FY 2005-2009 using current rates?

A. Revenues expected over the next 5 years, assuming current rates, are: $2,918 million in FY 2005 (*see,* WPRDS Documentation, WP-07-E-BPA-05A, Table 3.10); $2,986 million in FY 2006; $2,473 million in FY 2007; $2,396 million in FY 2008; and $2,351 million in FY 2009. *See,* WPRDS Documentation, WP-07-E-BPA-05A, Table 3.6.1.

Q. Why are a FY 2005 and a FY 2006 revenue forecast prepared?

A. The revenue forecast for this time period is used for several purposes, but for this proposal in particular the forecast is used to determine financial reserves for the beginning of the FY 2007-2009 rate period. Other uses include determining the level of the Financial Based (FB) and Safety Net (SN) Cost Recovery Adjustment Clauses (CRAC), as well as tracking financial performance.

Q. How much revenue is projected to be received from FY 2007-2009 using the proposed rates?

A. Revenues (excluding residential exchange revenue) expected over the period FY 2007 through FY 2009 are: $2,834 million in FY 2007; $2,748 million in FY 2008; and $2,696 million in FY 2009. *See,* WPRDS Documentation, WP-07-E-BPA-05A, Table 3.6.2.

Section 3. Changes Since BPA's May 2000 Rate Filing

Q. Has BPA's revenue forecast methodology changed since BPA's May 2000 Final Proposal?

A. Yes. The primary change is the use of a database model (i.e. the Revenue Forecast Application or RFA) to do the revenue calculations that had previously been done in the revenue forecast model.

Q. Why did BPA change to a database model?

A. BPA moved from a linked spreadsheet model to a database model because: (1) the linked spreadsheet model was getting too large and was difficult to modify; (2) to improve consistency of inputs; (3) to time stamp the results; and (4) make the same forecast numbers available to all users at the same time.

Q. What other changes have been made to BPA's May 2000 revenue forecast methodology?

A. One change is that Priority Firm (PF) sales and revenue had all been grouped together in BPA's May 2000 final proposal. Now these sales and revenue are divided into East and West Hub PF sales, as well as being further detailed as full requirements sales, partial requirements sales, PF block sales, and PF Slice sales. In addition there is a separate identification of pre-Subscription, Targeted Adjustment Charge (TAC), and irrigation mitigation sales for the East and West hubs.

Q. How were these sales grouped in the May 2000 final proposal?

A. All PF sales for the East and West hubs were grouped together, and the pre-Subscription sales were assumed to be made at the PF rate with a collar adjustment and an irrigation mitigation adjustment was made to correct for the difference between an approximate calculation using the PF rates and a more exact calculation using individual contract terms.

Q. Why did BPA make this change from its May 2000 final proposal?

A. BPA disaggregated sales to better monitor its forecasts. BPA is using individual contract terms to project revenue because it is more precise.

Q. Has BPA made any other changes to the revenue forecast methodology since BPA's May 2000 final proposal?

A. Yes. In BPA's May 2000 final proposal, the Low Density Discount (LDD) was assumed to be $14 million per year based on a review of historical LDD data. In the current proposal, the LDD is calculated for each customer and then totaled using the Revenue Forecast Application (RFA). As an example, we have included the results of the LDD calculation for a single customer. *See,* WPRDS Documentation, WP-07-E-BPA-05A, Table 3.11.

Q. Why did BPA make this change?

A. BPA made this change because now the precise projected amount of the LDD is quickly available without requiring extensive documentation.

Q. Has BPA made any other changes since the May 2000 final proposal?

A. Yes. One last change concerns the accounting treatment of the Conservation and Renewable Discount (C&RD). In BPA's May 2000 rate filing, the C&RD was treated as a reduction to revenues. In the current filing it is called the Conservation Rate Credit (CRC), and is not treated as a reduction in revenue but is instead treated as an expense.

Q. Why was this change made?

A. This change was made to comply with an accounting determination from BPA's auditor.

Section 4. Revenue from Subscription Contracts.

Q. What are regional Subscription contracts?

A. "Regional Subscription contracts" refers to those contracts that were signed with BPA's regional customers in 2000 for service at the PF, RL, and IP rate schedules.

Q. How is revenue from Subscription contracts estimated?

A. Revenue from Subscription contracts is estimated by multiplying the appropriate power rates by the projected billing determinants – Heavy Load Hour (HLH) energy, Light Load Hour (LLH) energy, demand at time of generation system peak (GSP demand), and total retail load (TRL).

Q. Where are the billing data obtained?

A. The billing data are stored in a database model and the revenues are calculated in that model. The results and the billing data are downloaded to a spreadsheet and included in the revenue forecast. Many customers have requested that BPA keep the data regarding their specific utility or company confidential.

Q. How can parties be certain that BPA's calculations are done properly?

A. BPA's results can be replicated by the parties because the revenue forecast displays the billing quantities, the rates, and the corresponding revenue formulas on those lines where revenue appears. The revenue formulas (which lines to add and multiply) are displayed in the left hand margins. *See,* WPRDS Documentation WP-07-E-BPA-05A, Tables 3.6.1 and 3.6.2.

Q. Do the formula results match the results coming from the RFA database?

A. Yes.

Section 5. Revenue from Long-term Contracts

Q. What are the regional and extra-regional long-term contracts?

A. Long-term contracts are those contracts for power sales, contract settlements, capacity sales, pre-Subscription contracts, contract buyouts or cashouts with a duration greater than one year from the initial date of contract implementation.

Q. What are the pre-Subscription contract sales?

A. Pre-Subscription contracts are contract sales made under the FPS rate schedule to firm power requirements customers at fixed rates. There are 16 pre-Subscription contracts and 6 Irrigation Mitigation (IRMP) contracts in the West Hub providing $71.5 million in revenue in FY 2006, declining to a single pre-Subscription contract and $5.2 million in FY 2007, and 6 IRMP contracts generating revenue of $3.3 million. There are 36 pre-Subscription contracts and 22 IRMP contracts in the East Hub providing $134.1 million in revenue in FY 2006, declining to ten pre-Subscription contracts and $51.3 million in FY 2007, and 22 IRMP contracts providing revenue of $17.4 million. The long-term contracts in the East and West Hubs include irrigation mitigation sales made under the FPS rate schedule and PF TAC sales ending in FY 2006. Approximately 650 aMW of long-term contracts in the East and West Hubs expire at the end of FY 2006, leaving 386 aMW compared to 1,032 in FY 2006. Most of those remaining sales (233 aMW) are at contractually fixed rates. The remainder of those contracts (153 aMW) are irrigation mitigation sales and the rate for those sales increases as the average PF rate increases.

Q. What long-term contracts are included in the Bulk Hub totals?

A. The long-term contracts included in the Bulk Hub sales include sales made at the

WNP-3 exchange rate, the WNP-3 Settlement with Portland General Electric Company (PGE), two capacity sales agreements, and a wind shaping agreement with PGE.

Q. How did BPA forecast revenue from regional and extra-regional long-term contracts?

A. Forecasting revenue from regional and extra-regional long-term contracts is done on a contract-by-contract basis in the revenue database, and then sorted into the East, West, or Bulk Hub. The contracts and revenues associated with long-term contracts are grouped together because the contracts contain confidential, business sensitive information, and every one of the contracts has slightly different terms, unlike Subscription power sales which are made under standard terms and rates.

Section 6. Revenue from Short-term Surplus Market Sales

Q. What are short-term surplus market sales?

A. Short-term surplus market sales are sales made from any generation that remains after all firm loads are served. Sales as short as one hour to as long as one year are considered short-term surplus market sales. For this rate proposal they are assumed to be monthly sales and take place either during LLH or HLH. The monthly energy sales, prices, and dollars for each water condition and the average used in this forecast can be found in WP-07-E-BPA-05A, Table 3.8.1.

Q. How were the short-term surplus market sales estimated?

A. Estimation of the short-term surplus market sales is explained in Section 1.17 of Wagner*, et al.,* WP-07-E-BPA-12, where a description of the calculation of short-term surplus market sales is located.

Q. What results were estimated using RiskMod?

A. RiskMod is used to estimate short-term surplus market sales and revenues, balancing power purchases and associated expense, and section 4(h)(10)(C) operational credits. Balancing power purchases and section 4(h)(10)(C) operational credits are discussed below.

Section 7. Revenue from Sales of Ancillary and Reserve Services

Q. How did BPA forecast revenue from ancillary and reserve services?

A. Forecasting revenue from the sale of generation inputs for ancillary and related services involves estimating the expected sales and the underlying costs of providing such services. The generation inputs for the ancillary and related services revenue forecast are explained in the testimony of BPA witnesses Bermejo*, et al*., WP-07-E-BPA-20.

Section 8. Treasury Credits

Q. What credits does BPA receive from the U.S. Treasury?

A. BPA receives section 4(h)(10)(C) credits to offset a portion of the additional costs BPA incurs due to changed operations for fish and wildlife recovery, and a credit for payments made to the Colville Tribe.

Q. What are the section 4(h)(10)(C) credits?

A. Section 4(h)(10)(C) is a provision of the Northwest Power Act that creates credits to offset a portion of the additional capital and the additional operating expenses BPA incurs due to changed operations that are paid on behalf of the non-power uses of the Federal Columbia River Power System (FCRPS). These credits are important because additional operating expenses can vary dramatically based on the effects of water conditions on non-power uses of the FCRPS The calculation of the section 4(h)(10)(C) credits is described in section 1.17 of Wagner, *et al.,* WP-07-E-BPA-12.

Q What are the amounts of the operational, expense, and capital credits that make up the 4(h)(10)(C) credit?

A. Operational credits average $36 million during the period FY 2007 through FY 2009, expense credits average $32 million, and capital credits average $8 million.

Q. How much is the Colville Tribe credit?

A. The Colville Tribe credit is fixed at $4.6 million per year beginning in 2002.

Section 9. Other Revenue

Q. How did BPA forecast other revenue components?

A. Some of the revenue forecast components are based on recent experience. This is true for miscellaneous revenue, downstream benefits, storage, Reserve Energy, and Irrigation Pumping Power revenue. For example, downstream benefits and Irrigation Pumping Power revenue are based on a historical average.

The remaining revenue components are forecast as follows. Energy Efficiency revenue is based on budgeted activity and generally equal to expenses. Colville Tribe credits are set in legislation. Section 4(h)(10)(C) credits are based on a percentage of program and operating costs associated with the Fish and Wildlife program. Green tag revenues are based on the projected output of renewable resources. Other miscellaneous revenue is an average of revenue over the past few years.

Q. What comprises miscellaneous revenue?

A. Miscellaneous revenue is composed of several items, including: reimbursement for GTA low voltage delivery charges and GTA/OATT transfer services, sale of unused transmission capacity, reimbursement for third-party transmission costs, contract administration fees, reimbursable power expenses, credits and waivers, and miscellaneous billing adjustments.

Section 10. Power Purchases and Purchased Power Expenses

Q. What are the types of purchased power and purchased power expenses that are documented in the revenue and purchased power forecast?

A. The first type of purchased power that this forecast documents is augmentation. Specifically, it documents three types of augmentation expenses, including deferred, residual, and the other augmentation expenses required to achieve critical period load resource balance in 2008 and 2009. Second, this forecast documents the balancing power purchases required to serve firm load obligations. Finally, there are other purchased power expenses from existing long-term contracts, particularly those costs of an Enron contract that are being recognized during the last three months of 2006, and some costs associated with Service and Exchange surplus energy purchase commitments.

Q. *Where are the purchased power costs documented?*

A. The purchased power costs are documented in Table 3.6.2 of WP-07-E-BPA-05A, and described in the testimony of Wagner, *et al.*, WP-07-E-BPA-12.

Q. *Are any elements of the revenue forecast likely to change prior to BPA's adoption of new power rates?*

A. Yes. Before new rates are filed we will know BPA's FY 2005 actual revenue, so the current revenue forecast will be replaced by actual results. We will also update our forecast of FY 2006 revenue to reflect our most current outlook for revenues based on billing data, runoff, and market conditions as BPA has in the past. This will have the effect of changing the level of expected reserves at the beginning of FY 2007.

Q. *Does this conclude your testimony?*

A. Yes.

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TESTIMONY OF

SARAH K. BERMEJO, REBECCA M. BERDAHL, THOMAS R. MURPHY,
GERY BOLDEN, AND RONALD J. HOMENICK

Witnesses for Bonneville Power Administration

SUBJECT: GENERATION INPUTS FOR ANCILLARY SERVICES

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TESTIMONY OF

SARAH K. BERMEJO, REBECCA M. BERDAHL, THOMAS R. MURPHY,

GERY BOLDEN, AND RONALD J. HOMENICK

Witnesses for Bonneville Power Administration

SUBJECT: GENERATION INPUTS FOR ANCILLARY SERVICES

Section 1. Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Sarah Bermejo. My qualifications are contained in WP-07-Q-BPA-03.

A. My name is Thomas Murphy. My qualifications are contained in WP-07-Q-BPA-42.

A. My name is Rebecca Berdahl. My qualifications are contained in WP-07-Q-BPA-02.

A. My name is Gery Bolden. My qualifications are contained in WP-07-Q-BPA-05.

A. My name is Ron Homenick. My qualifications are contained in WP-07-Q-BPA-17.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to explain the methodologies used to allocate generation costs to the provision of ancillary and other services (inter-business line charges). These costs and unit costs are used to forecast Power Business Line (PBL) revenue and expenses. This testimony also sponsors Section 4 of the Wholesale Power Rates Development Study, WP-07-E-BPA-05, and the accompanying Documentation, WP-07-E-BPA-05B.

Q. How is your testimony organized?

A. Our testimony is organized first by service. We then discuss the background information about each service. Following this, we describe PBL's proposed costing methodology. Finally, for each service, we explain and provide PBL's proposed generation input cost.

Q. How will the Transmission Business Line (TBL) use generation input costs and unit costs established in this power rate case in its Transmission and Ancillary Service rates?

A. In the 2006 transmission rate case, TBL developed formula rates to reflect, among other things, changes in PBL generation input rates established in the 2007 power rate case. Following the conclusion of the 2007 power rate case, TBL will set transmission and ancillary service rates for FY 2008-2009 according to the formulas in the respective rate schedules using the generation inputs determined in the power rate case.

Q. What services will you be pricing generation inputs for?

A. We will be pricing generation inputs for the following:

(1) Generation Supplied Reactive and Voltage Control

(2) Operating Reserves

  (a) Spinning

  (b) Supplemental (Non-Spinning)

(3) Regulating Reserve

(4) Energy and Generation Imbalance

(5) Generation Dropping

(6) Station Service

Section 2. Generation Supplied Reactive and Voltage Control

Q. What is generation supplied reactive power and voltage control?

A. In addition to supplying real power, Federal Columbia River Power System (FCRPS) generation facilities provide reactive power and voltage control to the transmission system. Generators routinely supply or absorb reactive power as necessary to maintain voltage and stability on the transmission grid. The North American Electric Reliability Council (NERC) Interconnected Operations Subcommittee defines reactive power supply from generation sources as the provision of reactive capacity, reactive energy, and responsiveness from interconnected operations services resources, available to control voltages and support operation of the bulk electric system. In Order No. 888, the Federal Energy Regulatory Commission (FERC) identified this function as an ancillary service. In order to provide this ancillary service, the transmission provider must acquire reactive power service from a generation source as a generation input.

Q. What is the distinction between reactive and real power?

A. For a detailed explanation of reactive power, refer to testimony from the Bonneville Power Administration's (BPA) 1996 rate case. *See,* Anasis, *et al.,* WP-96-D-BPA-31, Section 2. In general terms, reactive power, expressed in Volt-Ampere reactive (VAr), is the component of electrical power that is needed to maintain transmission voltage at required levels. Real power, expressed in Watts (W), is the other component of power and is the active force that enables electrical equipment to produce or absorb energy. Real power P and reactive power Q are added to form apparent or complex power S according to the relationships $S^2 = P^2 + Q^2$, where S is measured in megavolt-amperes (MVA), P in megawatts (MW), and Q in megavars (MVAr).

Q. What power costs are assigned to TBL for reactive power and voltage control?

A. The following power costs are assigned to TBL for reactive power and voltage control:

(1) A portion of the cost of FCRPS generation related equipment;

(2) Real power losses associated with the flow of reactive power in the generation equipment; and

(3) Costs associated with synchronous condensing (energy and plant equipment).

Q. How are reactive power and voltage control used by TBL?

A. In the same manner that spare MW capability is held in reserve to respond to unforeseen events, spare MVAr capability is also held to respond to unforeseen events. The reactive capability of FCRPS generators is held in reserve whenever possible so that the units have sufficient reactive capability available to respond immediately and automatically to voltage deviations during unforeseen events. These units absorb or supply reactive power dynamically as necessary to provide voltage stability.

Q. Why is reactive power and voltage control from generators such an important service?

A. Generators are the backbone of voltage control. They provide high-speed dynamic response to changes in voltage. To respond to unexpected system voltage deviations, utilities operating large transmission systems need to carry sufficient high-speed dynamic reactive reserves in their generators.

Q. Please explain why all of BPA's generating resources are included when assigning costs to TBL for reactive power and voltage control?

A. The flow of real power across the transmission system reduces voltage on the system. In order to maintain desired voltage levels, reactive power must be supplied at points along the transmission path. The supply of reactive power offsets the reduced voltages caused by the transfer of real power. Because reactive power increases the transmission system voltage, there are limitations on how much reactive power can be supplied at any one point on the transmission system. Also, it is not possible to transfer reactive power significant distances to support transmission system voltages. Therefore, reactive support must be distributed at various locations along a transmission path. BPA's generators located throughout the Northwest region provide this distributed reactive support.

Section 2.1. Description of the Proposed Methodology to Assign Generation Costs for Generation Supplied Reactive Power and Voltage Control

Q. What methodology is BPA proposing to assign generation costs to reactive power and voltage control?

A. BPA is proposing to apply the FERC approved *AEP* methodology to the total combined US Army Corp of Engineers (COE) and Bureau of Reclamation (BOR) facilities. As in the previous rate case, BPA proposes to assign generation costs to reactive power and voltage control by first identifying FCRPS generation components that are used to produce reactive power, referred to as electrical plant. The remaining components are used for real power production only. When making these identifications, BPA conforms to FERC guidance in determining which components to include in the allocation. For example, FERC has ruled that turbines are used for real power production only and should not be allocated to reactive power production. For each of the components that are used for both real and reactive power production, a fraction of the cost is allocated to reactive power and voltage control. *See,* Section 4.1.5 of the Wholesale Power Rate Development Study, WP-07-E-BPA-05.

Q. *Which components of generation facilities provide both real and reactive power?*

A. The electrical components of the generation facilities provide and/or transmit both real and reactive power. The electrical components include the generator stator and rotor, exciters, voltage regulators, step-up transformers, and generation integration facilities. Also included is 50 percent of accessory electrical equipment. Excluded are dam structures, turbines, nuclear reactors, land, or any other items associated with water or nuclear fuel.

Q. *How was the cost for electrical plant determined in the proposal for this rate proceeding?*

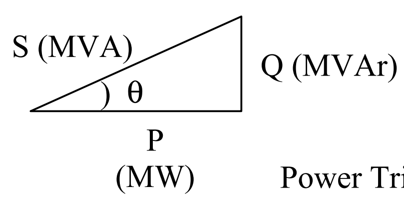
A. The cost of electrical plant was analyzed on a project-by-project basis and is provided in the documentation. An overall 50% ratio was applied to determine the allocation of costs to turbines versus generators, because these costs are not separated out for the COE and Reclamation projects. *See,* Section 4.4.3, Tables 4 and 5 of the Wholesale Power Rate Development Study Documentation, WP-07-E-BPA-05B.

Q. *Of those electrical components that provide both real and reactive power, how does BPA propose to allocate a portion of the costs to reactive power and voltage control?*

A. Based on industry standards, BPA proposes to use the equation $Q = 1 - pf^2$, where Q is reactive power and pf is the power factor, to allocate costs to reactive power, with a power factor of 0.95 for COE and Reclamation projects and 0.975 for Columbia Generating Station (CGS). First, electrical plant project costs are identified and reactive allocation determined. Second, these project costs are totaled. Lastly, the power factor (i.e., percentage) is applied to the total project cost identifying the appropriate allocation of reactive costs. The end result represents the percentage of electrical plant costs allocated to producing reactive power and voltage control. For example, $Q = 1 - 0.95^2$ results in a 10% cost allocation. *See,* Section 4.4.3, Tables 4 and 5 of the Wholesale Power Rate Development Study Documentation, WP-07-E-BPA-05B.

Q. Where does the equation $Q = 1 - pf^2$ come from?

The equation "$Q + 1 - pf^2$" is used in the *AEP* methodology to allocate electrical plant to generation supplied reactive and voltage control. It is a derived expression using the angle θ of the power triangle (illustrated below). For this rate case, the reactive component can be determined through proper application of the power factor while holding the angle constant.



Power Triangle

Q. Why is $Q=1-pf^2$ used to allocate costs to reactive power and voltage control?

A. The expression, $Q = 1 - pf^2$, is applied to the overall electric equipment plant costs described above, which is consistent with the FERC approved cost allocation method in *AEP*.

Q. What is the power factor?

A. The power factor used in the $Q = 1 - pf^2$ allocation is an indication of how much generation reactive capability is available to the system. A lower power factor (i.e., larger angle) indicates more reactive (Q) is provided by generation. Conversely, a higher power factor (i.e., smaller angle) indicates less reactive power is provided by generation.

Q. Why is BPA proposing to use a 0.95 power factor for the COE and Reclamation instead of the 0.90 power factor that was used in the last rate proceeding?

A. In the WP-02 rate proceeding, BPA used a 0.90 power factor for the COE and Reclamation projects. This was determined by measuring reactive and real power output of the COE and Reclamation projects operated at their peak efficiency. This was a reasonable way to allocate electric plant cost to reactive, because it is necessary to operate these generators in this fashion to support the transmission system. However, since the last rate case, FERC has made several rulings regarding cost allocation for generation supplied reactive. Most recently, in Order 2003A, FERC recognized that a 0.95 power factor is commonly used in the industry. For this rate proceeding, BPA proposes to determine the reactive allocation by applying this industry standard 0.95 power factor to all COE and Reclamation projects. It should be noted here that application of a single power factor is based upon the assumption that a common power factor angle can be applied to all projects to establish the amount of reactive (Q). This is a conservative assumption. Since the methodology proposed in this rate case is applied to all the COE and Reclamation plants combined, it is reasonable to use the industry standard power factor even though some of these plants are operated at a different power factor.

Q. Are CGS costs allocated in a similar fashion to that used for Reclamation and COE units?

A. Yes. Electrical components are identified, and a portion of the cost is allocated to reactive power and voltage control, but instead of using the 0.95 power factor, the 0.975 power factor of the nameplate rating was applied. In addition, rather than using the 50% allocation for generator and turbine, which is used for the Reclamation and COE units, a

74% allocation was used for CGS electrical plant. This is consistent with how CGS was accounted for in the last rate case proceeding.

Q. Please summarize the methodology for identifying and allocating the costs of generation electrical components to generation supplied reactive power and voltage control.

A. The costs of the generating plant equipment directly involved in providing reactive power and voltage control are identified. This electrical equipment includes the generators, stators, rotors, exciters, voltage regulators, step-up transformers, generation integration facilities and 50% of accessory electrical equipment. These components are then allocated to reactive power and voltage control for each project using a 50% allocation for generator/turbine and accessory equipment and a 74% allocation for CGS. An allocation percentage of 10% is applied for COE and Reclamation projects (power factor of 0.95) and 5% for CGS (power factor of 0.975). *See,* Section 4.1.5 of the Wholesale Power Rate Development Study, WP-02-E-BPA-05.

Q. What other generation costs are assigned to reactive power and voltage control?

A. The cost associated with synchronous condensing, both energy and facility upgrade costs, and energy associated with real power losses.

Q. What is a synchronous condenser?

A. A synchronous condenser is essentially a motor with an exciter system that enables it to absorb or supply reactive power as necessary to maintain voltage as needed by the transmission system. This is a dynamic process. Some FCRPS generating units are capable of operating in synchronous condenser or "condensing" mode. As with any motor, synchronous condensers consume real power.

Q. What is the distinction between generators and generators operated as synchronous condensers?

A. Normally, generating units are operated to produce real power and, at the same time, absorb or supply reactive power. However, at certain times real power production must be curtailed (*e.g.,* for fish related spill). At such times it may be undesirable to the transmission system operator to have the units idle as this degrades reliability. Under these conditions certain generating units are equipped to operate in condensing mode. Generators operated in condensing mode perform similarly to a generator that supports the transmission system, but the units are not capable of producing any real power while being operated in condensing mode. This is because the generator turbine is "de-watered" by shutting off the supply of water (and using air compressors, if necessary, to push water below the blades of the turbine) so that the unit may spin freely.

Q. *What are the facility upgrade costs for synchronous condensing?*

A. During the spring, summer, and autumn seasons fish constraints cause hydro units at The Dalles and John Day Dams to be unavailable for power production which degrades transmission system stability. Therefore, some of the hydro units have been modified to operate as synchronous condensers to support transmission system stability. All costs associated with synchronous condenser modifications and additions at The Dalles and John Day hydro projects identified in the previous rate case are carried forward into this rate case. These modifications were made specifically to enable the hydro plants to operate as synchronous condensers for transmission system stability; therefore, 100 percent of these costs are assigned to TBL.

Q. *What real power costs are assigned to TBL for synchronous condensing?*

A. When a generator is operated as a synchronous condenser, real power is consumed. In general, 100 percent of the cost of the real power consumed by synchronous condensers is identified and allocated to TBL. This method of allocation is consistent with the method applied during the previous rate case.

Q. *What energy costs are associated with real power losses?*

A. Energy loss occurs when moving power over the exciters, stator, rotor, GI facilities, and generation step up transformers. A portion of the cost of the real power consumed by these losses is allocated to reactive power and voltage control by applying the same 10 percent that is derived from the power factor to the overall losses.

Q. What is the total cost assigned to TBL for the generation inputs to provide reactive power and voltage control?

A. The proposed cost of generation inputs to provide reactive power and voltage control is $24.9 million ($18 million for COE and Reclamation facilities; $179,000 for CGS; $364,000 for synchronous condensers plant modifications; $4.1 million for energy consumed by synchronous condensing; and $2.15 million for real power losses). *See,* Section 4.4.3, Table 1 of the Wholesale Power Rate Development Study Documentation, WP-07-E-BPA-05B.

Section 3: Operating Reserves

Q. What are Operating Reserves?

A. Operating Reserves are described by the Western Electricity Coordinating Council (WECC) as the reserve generating capacity (or rights to interrupt delivery of generation) necessary to allow an electric system to recover from generation failures. Operating Reserves are the unloaded generating capacity, interruptible load, or other on-demand rights accessible within 10 minutes of a power system disturbance that are capable of sustained performance for up to one hour. Operating Reserves include both spinning reserves and supplemental (non-spinning) reserves.

Q. What does WECC require of Control Area Operators specific to Operating Reserves?

A. WECC Minimum Operating Reliability Criteria (MORC) provisions were developed with the intent to provide secure and reliable operation of the bulk electric systems in the Western Interconnection. MORC provisions cover, among other things, generator operation and performance that include minimum requirements for Operating Reserves. Each control area is expected to maintain minimum Operating Reserves to meet requirements for regulating margin, forced outages, interruptible imports, and on-demand obligations. Forced outage requirements must equal the sum of 5 percent of the load responsibility served by hydroelectric generation, plus 5 percent of the load responsibility served by wind-powered generation, plus 7 percent of the load responsibility served by thermal and other generation. At least half of this requirement must be met with Spinning Reserves.

Q. When are Operating Reserves needed?

A. Operating Reserves are needed to cover system disturbances across member control areas. According to the Northwest Power Pool (NWPP), a system disturbance occurs when generation is lost due to unit trips, loss of transmission path between generator and the network point of interconnection, internal plant equipment problems, or failure of a generating unit to start.

Q. Please describe BPA's relationship to the NWPP?

A. BPA is a participating member of the NWPP Reserve Sharing Program for Contingency Reserves. By participating in the Reserve Sharing Program, BPA is better positioned to meet the NERC disturbance control standard because we have access to a deeper and more diverse pool of shared reserve resources. This also increases efficiency because the shared reserve obligation for the group as a whole is less than the sum of each participant's reserve obligation computed separately. By sharing reserves, participants are entitled to use not only their own "internal" reserve resources, but may call on other participants for assistance if their internal reserves do not fully cover a contingency.

Q. What are Spinning Reserves?

A. Spinning reserves are a portion of Operating Reserves. Spinning reserves are provided by the unloaded generating capacity of the system's firm resources that are synchronized to the power system. These firm resources can respond immediately to system frequency deviations occurring from a system disturbance. WECC requires that each control area maintain a Spinning Reserve obligation equal to a minimum of 50 percent of its Operating Reserve obligation.

Q. What are Supplemental (Non-Spinning) Operating Reserves?

A. Supplemental Operating Reserves are that portion of the Operating Reserve obligation that do not meet the definition of Spinning Reserves. Generally, Supplemental Operating Reserves include both off-line generation available within 10 minutes notice and interruptible load that can be off-line within 10 minutes, both of which must be capable of sustained performance.

Section 3.1: Description of the Proposed Operating Reserve Cost Methodology

Q. Are transmission customers allowed to obtain Operating Reserves from other suppliers?

A. Yes. The *pro forma* tariff allows transmission customers the option of obtaining Operating Reserves either by (1) self-supply; (2) purchase from a third-party supplier; or (3) purchase from the control area operator. Currently, in the BPA control area, TBL's Business Practice for Operating Reserves allows transmission customers the ability to switch suppliers once a year to meet their entire reserve obligation to the BPA control area. If no election is made and if the transmission customer does not specify another supplier, purchasing from the control area operator is the default, and TBL must obtain enough Operating Reserves to meet the net needs of the control area.

Q. Have transmission contract holders elected to obtain Operating Reserves from sources other than TBL?

A. Yes, some transmission contract holders have elected to obtain Operating Reserves from other suppliers to meet their reserve obligation to the BPA control area.

Q. What impact do these elections have on PBL supplied generation inputs for Operating Reserves?

A. Because transmission customers are electing to self-supply or third-party supply their Operating Reserve obligation, the needed amounts of PBL supplied generation inputs for Operating Reserves has been reduced by approximately one-third.

Q. How is the PBL supplied reserve obligation to the BPA control area determined?

A. PBL's reserve obligation is determined by TBL first establishing the total reserve obligation for the BPA control area. The total reserve obligation for the BPA control area is 690 MW, which is determined by TBL and is consistent with WECC MORC. The PBL supplied reserve obligation is then determined by subtracting the amount of Operating Reserves customers have elected to self-supply or purchase from a third-party from the total reserve obligation. The net balance of 420 MW is estimated to be supplied by PBL through generation inputs provided to the control area operator.

Q. What is the revenue forecast for Operating Reserves?

A. The revenue forecast for generation inputs to provide Operating Reserves is $35 million per year for FY2007-2009 ($6.96 kW-mo * 420 MW * 12 months * 1,000). *See,* Section 4.1.3 of the Wholesale Power Rate Development Study, WP-07-E-BPA-05.

Q. What are the steps to derive the annual revenue forecast for Operating Reserves?

A. First, PBL calculated a ratio of 4.2%, which represents the percentage of the hydro system estimated to be used to provide the generation input for Operating Reserves. This ratio is determined by dividing PBL's share of BPA reserve obligation (420MW) by the total average hydro system uses (9,987 MW) (420MW / 9,987MW). Second, PBL applied this percentage to the power revenue requirement of $834 million to yield an adjusted power revenue requirement of $35 million (4.2% * $834 million). Third, PBL used the adjusted power revenue requirement to calculate the per unit charge of $6.96 kW-mo ($35 million divided by an annualized PBL's reserve obligation of 5,040,000 MW). The annualized PBL reserve obligation is derived from multiplying 420 MW by 12 months multiplied by 1,000. Finally, PBL calculated the annual revenue forecast by multiplying the per unit charge by the annualized PBL reserve obligation to yield $35 million per year (6.96kW-mo * 5,040,000 MW).

Q. How did PBL determine the revenue forecast for Operating Reserves?

A. PBL is basing the revenue forecast for Operating Reserves on the estimated annual hourly average PBL reserve obligation amount of 420 MW. This amount is determined by TBL, and is net of self-supply and third-party provided Operating Reserves to the BPA Control Area.

Q. What methodology is BPA proposing to use to allocate costs to Operating Reserves?

A. BPA is proposing a fully embedded cost of hydro methodology which includes the cost of the hydro projects that provide operating reserve obligations to the system; fish and wildlife program costs; generation integration (GI) and generator step-up (GSU) transformer costs; and the planned net revenues for risk (PNRR) associated with the hydrosystem. The generation costs assigned to Generation Supplied Reactive and Voltage Control is subtracted prior to determining the unit cost of Operating Reserves generation input to avoid double-counting. *See,* Section 4.1.5 of the Wholesale Power Rate Development Study, WP-07-E-BPA-05.

Q. Why did BPA choose an embedded cost methodology to allocate costs to Operating Reserves?

A. BPA has historically used an embedded cost methodology to set its power and transmission rates; this current power rate proposal is also based on embedded costs. In addition, use of an embedded cost methodology is consistent with other utilities' filings with FERC.

Q. Why is the cost of the Operating Reserves generation input based on all FCRPS hydro projects?

A. All FCRPS hydro projects contribute to providing Operating Reserves to meet BPA Control Area obligations. Therefore, all of the hydro projects qualify for cost recovery under the embedded cost methodology.

Q. Why does the embedded cost for Operating Reserves include Fish and Wildlife investment?

A. BPA's Fish and Wildlife costs result directly from production of real power at the FCRPS hydro facilities that provide Operating Reserves to meet BPA Control Area obligations. Fish and wildlife programs are necessary to protect, mitigate, and enhance fish and wildlife affected by the development and operation of the FCRPS hydro projects. This approach is consistent with other utilities' FERC filings, where environmental compliance costs have been included in the embedded cost of Operating Reserves.

Q. Why does the cost for Operating Reserves exclude the costs of CGS and the non-performing assets (including WNP-1, -3, and Trojan decommissioning), conservation, and residential exchange?

A. CGS is primarily a base-loaded plant and is not dispatched to provide Operating Reserves. The other assets and programs do not contribute directly to the cost of providing Operating Reserves to meet BPA Control Area obligations and therefore their costs are excluded from the Operating Reserves calculation.

Q. Does the same methodology chosen to allocate costs to Operating Reserves apply to both Spinning Operating Reserves and Supplemental Operating Reserves?

A. Yes. BPA's choice of methodology is an embedded cost that includes all assets that provide Operating Reserves for the balancing needs of the BPA Control Area. All FCRPS hydro projects contribute to providing Operating Reserves necessary to meet BPA Control Area obligations.

Q. How is the adjusted revenue requirement for inter-business line charges (generation input rate) for Operating Reserves calculated?

A. First, the revenue requirement for all FCRPS hydro projects (including fish and wildlife, GSU, and GI costs) was determined. *See,* Revenue Requirement Study, WP-07-E-BPA-02. This revenue requirement was reduced by the generation input cost for reactive power and voltage control. The share of the power revenue requirement for Operating Reserves is found by multiplying the revenue requirement by the percentage of the PBL reserve obligation in relation to the total system uses. *See,* Section 4.4.1 of the Wholesale Power Rate Development Study Documentation, WP-07-E-BPA-05B.

Q. How is the per unit capacity charge for inter-business line charges (generation input rate) for Operating Reserves calculated?

A. The per unit charge of $6.96 kW-month is calculated by dividing the adjusted annual FCRPS hydro revenue requirement of $35,092,090 by the PBL Operating Reserve obligation of 420 MW, times 12 months, times 1,000. The adjusted FCRPS hydro revenue requirement is determined from the total FCRPS hydro revenue requirement of $834,439,768 divided by 4.2%, which represents the proportion of PBL's Operating Reserve obligation of 420 MW to the total average system uses of 9,987 MW. The total annual average system uses are the sum of 9,217 MW of average annual hydro generation, 420 MW of PBL operating reserve obligation, and 350 MW of control area Regulating Reserve obligation.

Q. Does this per unit capacity charge for inter-business line charges allow for an adjustment?

A. Yes. The per unit capacity charge is established as an up-to cost, which means that the business lines can decide to adjust the cost that is charged to the TBL through the inter-business line bill. This rate design provides a maximum cap on the generation input cost that PBL can charge to the TBL for provision of service and allows the flexibility for the business lines to mutually agree to an adjusted cost.

Q. How would an adjustment be determined and applied?

A. An adjustment would be determined through mutual agreement between the business lines based on balancing criteria consistent with the embedded cost of hydro methodology and protecting the reliability of the federal power system. This generation input cost would be applied to the inter-business line bill that PBL issues to TBL for PBL supplied generation inputs.

Q. How will PBL allocate the revenues it receives from TBL?

A. PBL is proposing to not have an Operating Reserves credit in the base rate calculation. Rather, PBL is proposing to provide an Operating Reserve Credit (ORC) to firm power requirements customers that elect to purchase Operating Reserves from TBL that are supported by generation inputs supplied by PBL. This credit will be on the customer's power bill. The ORC better reflects actual revenues PBL receives from generation inputs provided to TBL, and ensures cost recovery consistent with the power revenue requirement. *See,* Rate Design Testimony, Section 8, WP-07-E-BPA-13.

Q. How is energy charged for when reserves are called upon to deliver energy?

A. When Operating Reserves are utilized to provide energy, that energy will be priced based on an hourly energy index in the PNW, as determined by PBL. PBL will determine an energy price index based on volume of trade, liquidity, and price transparency that best reflects market value. In the absence of an hourly energy price index, PBL will apply the above criteria to select another appropriate energy price index.

Section 4: Regulating Reserves

Q. What are Regulating Reserves?

A. Regulating Reserves are the generation inputs required to provide regulation and frequency response service, which is the generating capacity of a power system that is immediately responsive to Automatic Generation Control (AGC) control signals without human intervention. Regulation and frequency response service is required to provide AGC response to balance load and generation fluctuations effectively. In order to maintain compliance with NERC AGC Control Performance criteria, TBL currently estimates this requirement at an annual hourly average amount of 350 MW, which is comprised of 200 MW for load following and 150 MW for load regulation.

Q. Where does the annual hourly average Regulating Reserve Requirement come from?

A. TBL evaluates the amount of regulating reserves that are needed based on generation in the control area and load following requirements to meet minimum NERC AGC Control Performance Standard Criteria. TBL recently reevaluated these historic impacts and the numbers provided for this rate proposal come from this evaluation.

Section 4.1: Description of the Proposed Regulating Reserves Cost Methodology

Q. *What is the revenue forecast for Operating Reserves?*

A. The revenue forecast for generation inputs to provide Regulating Reserves is $14.9 million per year for FY 2007-2009 ($8.29 kW-mo * 150 MW * 12 months * 1,000) *See,* Section 4.1.4.9 of the Wholesale Power Rate Development Study, WP-07-E-BPA-05.

Q. *What are the steps to derive the annual revenue forecast for Regulating Reserves?*

A. First, PBL calculated a ratio of 3.9%, which represents the percentage of the "Big 10" hydro projects estimated to be used to provide the generation input for Regulating Reserves. This ratio is determined by dividing BPA regulating reserve obligation (350MW) by the total average "Big 10" hydro system uses (8,927 MW) (350MW / 8,987MW). Second, PBL applied this percentage to the "Big 10" power revenue requirement of $722 million to yield an adjusted power revenue requirement of $28 million (3.9% * $722 million). Third, PBL used the adjusted power revenue requirement to calculate the per unit charge of $6.74 kW-mo ($28 million divided by an annualized BPA reserve obligation of 4,200,000 MW). The annualized PBL regulating reserve obligation is derived from multiplying 350 MW by 12 months multiplied by 1,000. Finally, PBL calculated the annual revenue forecast by adding the per unit charge of $6.74 kW-month to the AGC Adder of $1.55 kW-month then multiplying this total per unit amount of $8.29 kW-month by TBL's share of the regulating reserve obligation (150 MW of the 350 MW) to yield $14.9 million per year (6.74 kW-month + 1.55 kW-month * 150 MW *12 months * 1000).

Q. *Why did BPA choose an embedded cost methodology to allocate costs to regulating reserves?*

A. BPA has historically used an embedded cost methodology to set its power and transmission rates; this current power rate proposal is also based on embedded costs. In addition, use of an embedded cost methodology is consistent with other utilities' filings with FERC.

Q. Why is the embedded cost for regulating reserves calculated based on only the "Big 10" projects?

A. The "Big 10" hydro projects are equipped to provide AGC and are routinely called upon to do so. These projects are connected to the AGC system to meet BPA Control Area obligations.

Q. Why does the embedded cost for regulating reserves include fish and wildlife investment?

A. BPA's fish and wildlife costs result directly from production of real power at the FCRPS hydro facilities that provide regulating reserve to meet BPA Control Area obligations. Fish and wildlife programs are necessary to protect, mitigate, and enhance fish and wildlife affected by the development and operation of the FCRPS hydro projects. This approach is consistent with other utilities' FERC filings, where environmental compliance costs have been included in the embedded cost of regulating reserves. The "Big 10" share based on capacity (89 percent) is allocated to the cost of providing regulation service.

Q. Why do costs for regulating reserves exclude the costs of CGS and the non-performing assets (including WNP-1, –3, and Trojan decommissioning), conservation, and residential exchange?

A. Similar to Operating Reserves, CGS is primarily a base-loaded plant and is not dispatched to provide regulating reserve. The other assets and programs do not contribute directly to the cost of providing regulating reserve to meet BPA Control Area obligations.

Q. Are there other costs allocated to regulating reserve generation inputs?

A. Yes, the AGC adder.

Q. What is the AGC adder?

A. The AGC adder is composed of additional costs that BPA incurs at the hydro projects due to the obligation to provide AGC response. These costs are a result of operating the hydro units by constantly changing their power output to follow instantaneous changes in system loading and thus maintain system frequency.

Q. What costs are included in the AGC adder calculation?

A. There are two cost components included in the AGC adder. The first cost component is the loss of efficiency due to the hydro unit being required to operate less efficiently than a base-loaded unit. The second cost component is an incremental increased operation and maintenance cost because the generating unit is required to operate more dynamically than a base-loaded unit. *See,* Section 4.1.4.3 through 4.1.4.6 of the Wholesale Power Rate Development Study, WP-07-E-BPA-05.

Q. How is the per unit charge for inter-business line charges for regulating reserve calculated?

A. The revenue requirement for the "Big 10" FCRPS hydro projects was determined. *See,* Revenue Requirement Study, WP-07-E-BPA-02. The per unit base charge of $6.74 kw-mo is calculated using an embedded cost methodology similar to Operating Reserves except that hydro costs are specific to the "Big 10" hydro projects where the average total system uses (generation, and PBL Operating Reserve obligation) are multiplied by 89 percent and then added to the BPA Regulating Reserve obligation. This amount is divided into the annual "Big 10" hydro revenue requirement of $722,476,192. The share of revenue requirement for Regulating Reserves is found by multiplying the revenue requirement by the percentage of the BPA Regulating Reserves obligation in relation to the total system uses. The AGC adder of $1.55 kW-month is added to the per unit base charge of $6.74 kw-mo to arrive at a total per unit charge of $8.29 kW-month. *See,* Section 4.1.4.7 of the Wholesale Power Rate Development Study, WP-07-E-BPA-05.

Q. How will this per unit charge be applied to TBL?

A. PBL proposes to charge the TBL on a per unit basis based on TBL's Regulating Reserve obligation of 150 MW.

Q. How is the Regulating Reserve obligation for the control area determined?

A. TBL evaluates the impact on the amount of regulating reserves that are required to meet NERC Control Performance Standards (CPS) criteria required of control area operators. TBL determined that the annual average BPA regulating reserve obligation is estimated to be 350 MW and the TBL share for regulation is 150 MW. The remaining 200 MW is capacity available to meet the load following needs for PBL's requirements customers. *See,* Section 4.1.4.7 of the Wholesale Power Rate Development Study, WP-07-E-BPA-05.

Q. Does this per unit capacity charge for inter-business line charges allow for an adjustment?

A. Yes. The per unit capacity charge is established as an up-to cost which means that the business lines can decide to adjust the cost that is charged to the TBL through the inter-business line bill. This rate design provides a maximum cap on the generation input cost that PBL can charge to the TBL for provision of service, but allows the flexibility for the business lines to mutually agree to an adjusted cost.

Q. How would an adjustment be determined and applied?

A. An adjustment would be determined through mutual agreement between the business lines based on balancing criteria consistent with embedded cost of hydro methodology and protecting the reliability of the federal power system. This generation input cost would be applied to the inter-business line bill that PBL issues to TBL for PBL supplied generation inputs.

Section 5: Generation to Supply Imbalance Needs

Q. What is energy imbalance?

A. In Order No. 888, FERC defined "energy imbalance" as an ancillary service. Energy imbalance is provided when there is a difference between scheduled and actual delivered amounts of energy to a load in the BPA control area over a single hour.

Q. What is generation to supply energy imbalance needs?

A. As the control area operator, the TBL supplies energy to maintain load-resource balance within the BPA control area. When actual load varies from scheduled deliveries, TBL must acquire generation to supply energy imbalance needs to make up the difference. TBL may acquire this generation input from the PBL.

Section 5.1: Description of the Proposed Imbalance Cost Methodology

Q. What is the PBL revenue forecast for generation to meet energy imbalance needs?

A. The PBL forecast is $0 revenue for generation to meet energy imbalance needs. This forecast is consistent with TBL's revenue forecast in the 2006 - 2007 Transmission Rate Case Settlement Agreement.

Q. How does PBL propose to charge TBL for energy when generation to meet energy imbalance needs is called upon for delivery?

A. When generation is called upon, the energy taken to meet imbalance needs will be priced based upon an hourly index in the Pacific Northwest, as determined by PBL, and in accordance with TBL's Open Access Transmission Tariff. PBL will determine an energy price index based on volume of trade, liquidity, and price transparency that best reflects market value. In the absence of an hourly energy price index, PBL will apply the above criteria to select another appropriate energy price index.

Q. Are there any other balancing services provided to the TBL by the PBL?

A. Yes, generation imbalance is also provided in the same manner and with the same $0 revenue forecast as energy imbalance. The distinction in service is that generation imbalance is provided when there is a difference between scheduled amounts and actual generation amounts in the BPA control area over a single hour.

Section 6: Generation Dropping

Q. What are remedial action schemes?

A. The BPA transmission system is interconnected with several other transmission systems. A remedial action scheme (RAS) is an automatic controlled operation that occurs during a system emergency condition. It provides stability to the interconnected system, and maximizes transmission capacity, while minimizing service disruptions or technical problems on the transmission systems.

Q. What is generation dropping?

A. Generation dropping is a particular kind of RAS that the PBL provides to the TBL. PBL provides this service by instantaneously dropping large increments of generation (600 MW and greater). In order to satisfy reliability requirements, the generation must be dropped, virtually instantaneously, from the transmission grid.

Q. What would be the consequence of PBL not providing this service?

A. Transmission reliability would be compromised at the current transmission path ratings and the transmission paths would consequently be derated or new facilities would have to be constructed to maintain existing transmission capacity.

Q. Which hydro projects provide the most generation dropping service?

A. Although not an exhaustive list, the primary hydro projects that provide most of PBL's generation dropping services are Grand Coulee, Chief Joseph, John Day, McNary, The Dalles, Libby, and Dworshak.

Section 6.1: Description of the Proposed Generation Dropping Cost Methodology

Q. What is the PBL revenue forecast for generation dropping?

A. The revenue forecast associated with generation dropping that is allocated to the TBL is $396,071.

Q. What factors are considered in the cost analysis for generation dropping?

A. Two factors contribute to the costs of generation dropping. First, the generation drop service or "forced outage duty" imparts a wear and tear component on equipment that will incrementally decrease the life and increase the maintenance required by the unit. This wear and tear component results from the severe duty imposed by generation dropping. Second, decreased unit life and increased maintenance reduces revenues during replacement or overhaul of the equipment. *See,* Section 4.2.1 of the Wholesale Power Rate Development Study, WP-07-E-BPA-05.

Q. How has PBL updated the project costs of generation dropping?

A. PBL conducted interviews with the Reclamation and the COE (owners of the Columbia River system plants) to validate findings of the engineering company that PBL contracted with to collect relevant project cost data for the prior rate proceeding. To update these project costs PBL applied an inflation factor to plant and equipment costs to reflect average costs for the rate period.

Q. Are the stresses experienced during generation dropping the same as those stresses experienced during regular duty?

A. Some stresses are the same, but others are more severe such as voltage spikes and the rotating mechanical stresses that increase wear and tear of the units during generation dropping.

Q. How were the costs of increased stresses calculated?

A. The engineering company retained by PBL prior to the last rate proceeding consulted manufacturers and designers to estimate the costs of decreased life of the equipment and increased maintenance requirements imposed by generation dropping.

Q. What other cost were analyzed to determine the cost of generation dropping?

A. Lost revenue from increased unit downtime was projected.

Q. Why does the cost analysis only focus on the large generation units at Grand Coulee?

A. There are several remedial action schemes that require arming and dropping other generating units on the FCRPS. The PBL incurs most of its costs dropping the large units at Grand Coulee. Therefore, BPA chose the Grand Coulee Third Powerhouse hydroelectric units (which each exceed 600 MW capacity) as a representative sample of costs incurred by the PBL to provide generation dropping to TBL. This approach yields the highest impact to PBL revenues.

Q. Are other hydro projects that provide generation dropping included in the cost analysis?

A. No. Though there are costs incurred when we drop the smaller units, they are of significantly lower magnitude and financial impact than the costs of dropping the big Grand Coulee units and are excluded from this analysis.

Q. What are the various components that contribute to the cost allocation for generation dropping?

A. The proposed cost allocation includes $3,198 for additional maintenance cost, $52,051 in deterioration and risk costs to replace damaged or failed equipment, and $208,798 for lost revenues. This sum of $264,047 is multiplied by 1.5, which represents the average number of times a Grand Coulee generator is dropped in a year based on RAS, which results in a total cost of $396,071 per year.

Section 7: Station Service

Q. What is station service?

A. Real power taken directly off the BPA power system for use by TBL at substations and other facilities. The power is needed for the operation of TBL substations and other facilities such as Big Eddy/Celilo Complex and the Ross Complex.

Q. Is station service metered?

A. Generally, no. There are few locations on the BPA system where station service usage is metered. For determining the cost allocation of Station Service, PBL proposes to establish a method for estimating the usage of station service based on historical data.

Section 7.1: Description of the Proposed Station Service Cost Methodology

Q. What is the PBL revenue forecast for station service?

A. PBL proposes the cost of station service allocated to the TBL to be $2.29 M. *See,* Section 4.2.2 of the Wholesale Power Rate Development Study, WP-07-E-BPA-05.

Q. What cost is allocated to station service?

A. PBL proposes to allocate the real power costs for power supplied by the PBL for use at BPA substations to capture station service costs. This does not include station service that is being purchased by the TBL from another utility or supplied by another utility through contractual arrangements.

Q. What is the method used to allocate costs to station service?

A. Since most TBL substations do not have meters for station service, the proposed methodology is based on the amount of primary station service transformation installed at each substation location multiplied by an average load factor associated with average substation service usage. The load factor is derived from historical data. Since the Ross Complex and Big Eddy/Celilo Complex are not normal substation facilities and there are meters installed to measure station service, the historic average station service kilowatthour usage for the Ross Complex and the Big Eddy/Celilo Complex has been added to the calculated numbers for the other substations to develop the total station usage for the system. *See,* Section 4.2.2.1 of the Wholesale Power Rate Development Study, WP-07-E-BPA-05.

Q. How is the PBL revenue forecasted for station service determined?

A. The total average system station service usage amount of 6,368,389 kWh/month or 8.8 MW is multiplied by an average PF rate of 30.0mills/kWh times 12 months to establish the annual revenue forecast.

Q. Does this conclude your testimony?

A. Yes.

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TESTIMONY OF

REBECCA M. BERDAHL, DAVID L. GILMAN, AND RONALD J. HOMENICK

Witnesses for Bonneville Power Administration

SUBJECT: SEGMENTATION OF U.S. ARMY CORPS OF ENGINEERS AND BUREAU OF RECLMATION TRANSMISSION FACILITIES

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Section 1. Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Rebecca Berdahl. My qualifications are contained in WP-07-Q-BPA-02.

A. My name is David Gilman. My qualifications are contained in WP-07-Q-BPA-13.

A. My name is Ronald Homenick. My qualifications are contained in WP-07-Q-BPA-17.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to sponsor the segmentation analysis of the U.S. Army Corps of Engineers (COE) and Bureau of Reclamation (Reclamation) transmission facilities. *See,* Section 4.3 of the Wholesale Power Rate Development Study, WP-07-E-BPA-05.

Q. How is your testimony organized?

A. Our testimony includes four sections including this introductory Section. Section 2 is an explanation of the segmentation analysis of the COE and Reclamation transmission facilities. Section 3 is a description of the treatment of Generation Integration (GI) costs. Section 4 is a discussion of the calculation of the revenue credit for COE and Reclamation Network and Delivery facilities.

Section 2. COE and Reclamation Segmentation Analysis

Q. Please explain the proposed treatment for COE and Reclamation transmission costs?

A. A small portion of COE and Reclamation investment is associated with transmission facilities. In previous rate cases, COE and Reclamation transmission investment was identified and included in the transmission repayment study and the associated annual costs were included in the transmission revenue requirement. In the WP-02 rate case, however, BPA included all COE and Reclamation investments, including those associated with transmission facilities, in the generation repayment study and the generation revenue requirement. So these investment costs were paid by PBL, but functionalized to the TBL. *See,* Revenue Requirement Study, WP-02-E-BPA-02. In that prior rate case, the investment associated with the transmission facilities owned by the COE and Reclamation was identified and assigned to the appropriate transmission segment. In addition, the investment for COE and Reclamation transmission facilities was based on updated actual investment data from the COE and Reclamation. BPA proposes to continue this treatment for the COE and Reclamation transmission costs for the present rate period.

Q. Why is it necessary to assign the investments of COE and Reclamation transmission facilities to the transmission segments?

A. COE and Reclamation transmission facilities perform GI, Network, and Delivery functions. The investment of transmission facilities must be identified and segmented so the costs can be assigned to the appropriate use. GI cost is assigned to be recovered through power rates, while the proposed costs of COE and Reclamation Network and Delivery facilities are assigned to be recovered through transmission rates.

Q. How are COE and Reclamation transmission facility investments assigned to the transmission segments?

A. The assignment of transmission facility investment to the appropriate segment is consistent with the most recent TBL Segmentation Study. The segment definitions used to segment COE and Reclamation Network and Delivery facilities are from the 2002 Final Transmission Proposal Segmentation Study, TR-02-FS-BPA-02. The GI segment definition includes generator step-up (GSU) transformers which step the power up from generation to transmission voltage.

Q. Does this proposal determine the segmentation for BPA-owned transmission facilities?

A. No. The segmentation of BPA-owned transmission facilities is done in the transmission rate case. To the extent the segment definitions change in future transmission rate cases, the cost of the COE and Reclamation facilities will be placed in the appropriate segment.

Section 3. Generation Integration

Q. What are Generation Integration (GI) facilities?

A. These are the transmission facilities located between the generator and the Network stations, including step up transformers, power house lines or cables, and switching equipment at the Network station for the power house line. This is consistent with the GI segment definition in the 2002 Final Transmission Proposal Segmentation Study, TR-02-FS-BPA-02.

Q. What are GSUs?

A. These are the facilities at the Federal projects that transform the voltage of the power from that of the generator to that of the local transmission system. The GSUs are all owned by the project owner. In prior rate proceedings, the GSU costs were not separately identified from generation costs, and thus, were included in the generation revenue requirement. Separate identification of the GSUs facilitates the allocation of these costs to generation inputs for ancillary services. *See,* Bermejo, *et al.,* WP-07-E-BPA-20. All GI costs, including GSUs, will be assigned to be recovered through power rates with a portion of these costs being allocated to TBL through the generation inputs.

Q. Where is the GI cost determined?

A. The GI facilities have been separated into two portions— those owned by the COE and Reclamation, and those owned by BPA. The COE and Reclamation GI annual costs were included directly in the generation revenue requirement. The annual cost of BPA GI facilities was estimated to be $8.5 million based on the GI costs for BPA-owned facilities in the Power Function Review. *See,* Section 4.3 of the Wholesale Power Rate

Development Study, WP-07-E-BPA-05. *See, also*, the 2002 Final Transmission Proposal Segmentation Study, TR-02-FS-BPA-02. This GI cost is treated as an expense in the generation revenue requirement. *See,* Revenue Requirement Study, WP-07-E-BPA-02.

Section 4: Calculation of Revenue Credit for COE and Reclamation Network and Delivery Facilities

Q. Please describe the revenue credit to the generation revenue requirement for the COE and Reclamation transmission facilities.

A. The credit to the generation revenue requirement is for COE and Reclamation transmission facilities that perform a Network or Delivery function. The annual cost of these facilities (operation and maintenance, depreciation, and interest expense) is calculated and assigned to transmission and will be recovered through transmission rates. The segmentation analysis determines the COE and Reclamation investment in these segments, which is used to develop the associated annual cost of $6.8 million. *See,* Documentation for Revenue Requirements Study, WP-07-E-BPA-11. This annual cost is a revenue credit to the generation revenue requirement and will be an expense in the transmission revenue requirement when transmission rates are developed. *See,* Section 4.3 of the Wholesale Power Rate Development Study, WP-07-E-BPA-05B. Inclusion of the cost of COE and Reclamation Network and Delivery facilities in the transmission revenue requirement is consistent with prior rate proceedings.

Q. Does this conclude your testimony?

A. Yes.

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TESTIMONY OF

LESLIE J. POMPEL AND SCOTT D.WILEY

Witnesses for Bonneville Power Administration

SUBJECT: GENERAL TRANSFER AGREEMENT (GTA) DELIVERY CHARGE

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TESTIMONY OF

LESLIE J. POMPEL AND SCOTT D. WILEY.

Witnesses for Bonneville Power Administration

SUBJECT: GENERAL TRANSFER AGREEMENT (GTA) DELIVERY CHARGE

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Leslie J. Pompel and my qualifications are contained in WP-07-Q-BPA-45.

A. My name is Scott D. Wiley and my qualifications are contained in WP-07-Q-BPA-52.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to describe the GTA Delivery Charge, explain how it was developed, and discuss the proposed methodology for establishing the rate for the period of October 1, 2007 through September 30, 2009.

Q. How is your testimony organized?

A. Section 1 of our testimony describes the purpose of the GTA Delivery Charge. Section 2 provides a description of the GTA Delivery Charge, explains how BPA developed the charge previously, and discusses the justification behind the establishment of the GTA Delivery Charge. Section 3 explains BPA's proposed methodology for establishing the GTA Delivery Charge during the last two years of this three year rate period. Section 4 establishes the proposed revenue forecast for the GTA Delivery Charge. This testimony sponsors the Wholesale Power Rate Development Study, WP-07-E-BPA-05.

Section 2. GTA Delivery Charge

Q. What is the GTA Delivery Charge?

A. The GTA Delivery Charge is a Power Business Line (PBL) rate for deliveries of Federal power made over a third-party transmission system at voltages below 34.5 kV.

Q. Who pays the GTA Delivery Charge?

A. The GTA Delivery Charge applies to customers receiving service over third-party transmission facilities when that service is below 34.5 kV. This third-party transmission service is commonly referred to as "transfer service" and includes grandfathered contracts, Open Access Transmission Tariff service, and other transmission arrangements. The customer only pays the GTA Delivery Charge if they receive transfer service below 34.5 kV and they are not already paying TBL's Utility Delivery Charge for that particular point of delivery.

Q. How has PBL previously developed the GTA Delivery Charge?

A. The GTA Delivery Charge was previously set in the FY 2002, 2004, and 2006 Transmission Business Line rate case settlement agreements. The current GTA Delivery Charge is set through September 30, 2007. PBL has been a party to these TBL rate case settlement agreements. Pursuant to these settlement agreements, the GTA Delivery Charge was set to the rate level of the Utility Delivery charge noted in the applicable TBL Transmission and Ancillary Service Rate Schedule.

Q. Why is PBL proposing to set the GTA Delivery Charge in PBL rate case instead of in the TBL rate case?

A. The GTA Delivery Charge is a rate that is paid by a subset of PBL's power customers, and represents a responsibility taken on by PBL, not TBL. PBL originally intended to establish the GTA Delivery Charge in the PBL rate case in 2000. However, due to an administrative oversight, the rate had to be established in the TBL rate proceeding. To remedy this oversight and return the GTA Delivery Charge to the power rate case, PBL is setting the charge in the WP-07 rate case for the last two years of this rate period (October 1, 2007 through September 30, 2009).

Q. Please explain the TBL settlement provision concerning the GTA Delivery Charge.

A. As noted above, the GTA Delivery Charge was previously set in the 2006 Transmission rate case settlement agreement to mirror TBL's Utility Delivery rate. Pursuant to this settlement, the GTA Delivery Charge is set to $1.119 per kilowatt-month until September 30, 2007.

Q. What is PBL's proposal for the GTA Delivery Charge for the period of October 1, 2007, through September 30, 2009?

A. For the period of October 1, 2007 through September 30, 2009, PBL is proposing to continue to set the GTA Delivery Charge to the same rate as TBL's posted Utility Delivery rate. As adjustments are made to the Utility Delivery rate in future TBL rate cases, PBL proposes to reflect these changes in the GTA Delivery Charge.

Q. What is the justification for the GTA Delivery Charge?

A. PBL previously determined, that as a matter of policy, it would charge customers for transfer service to points of delivery below 34.5 kV. This result was reached, in part, because customers served directly by TBL pay TBL's posted Utility Delivery Charge for deliveries over certain low voltage and distribution facilities. TBL generally breaks out costs for lower voltage facilities acquired before FERC Order 888 that, under the FERC open access Tariff, would be considered Direct Assignment or distribution facilities if they were acquired after that. TBL's "postage stamp" Delivery Charge is in lieu of directly assigning the cost of those pre-888 facilities to the customers who take delivery. Under standard utility practice a utility would not recover the cost of most of these facilities through general network or point-to-point transmission rates, because they mainly benefit only those customers taking "delivery" at those particular facilities.

Section 3. Proposed Methodology for GTA Delivery Charge

Q. What is the proposed methodology for the GTA Delivery Charge?

A. PBL proposes to mirror the TBL's Utility Delivery rate. This PBL charge is proposed to be for customers that take service directly from TBL delivered at voltages below 34.5 kV. The proposal to charge a GTA Delivery Charge is consistent with PBL's attempts to make transfer service closely resemble service to utilities directly connected to TBL.

Q. Why is PBL proposing to mirror the GTA Delivery Charge with TBL's Utility Delivery rate, instead of making its own delivery charge rate based on a break-out of actual GTA low voltage costs?

A. PBL proposes to mirror TBL's Utility Delivery rate for two reasons. First, setting the GTA Delivery Charge equal to TBL's Utility Delivery Charge provides customers served through transfer agreements better comparability with customers that take service directly from TBL's transmission system. A number of customers have requested in various forums that BPA treat customers served by third-party systems in a manner comparable with customers directly connected to TBL's transmission system. Under PBL's proposal, customers directly connected to TBL's transmission system and customers served through transfer over third-party systems would be charged the same rates for services over low voltage facilities.

Second, at this point, PBL does not have enough facilities and service cost information to develop a stand-alone GTA Delivery Charge. To establish a specific PBL charge, PBL would need to gather cost data from all of its transfer service providers, make various interpretations of that data where providers have different cost recovery methods, different cut-off voltages, rates of return, tax rates, etc., and draw potentially controversial conclusions about which costs should go into the proposed rate. Meanwhile, given conversions from pre-FERC 888 contracts to OATT and other changes due to industry restructuring and load growth, the relevant data and corresponding charges from the transfer providers remain in a state of flux. In the future, PBL may conduct the necessary information gathering and analysis to adopt a specific PBL GTA Delivery Charge.

Section 4. Revenue Forecast for GTA Delivery Charge

Q. What is the revenue forecast for the GTA Delivery Charge?

A. The approximate revenue associated with the GTA Delivery Charge is forecasted to be

$2.3 million per year. This is determined from calculating the historical peak demand of 6,324 kW-months, averaged over a 12 month period, multiplied by 27 low voltage Point of Delivery (provided for in GTA and other non-Federal transmission service agreements for low voltage delivery), multiplied by the GTA Delivery Charge of $1.119 kW-month, then multiplied by 12 months, to yield an annual average amount.

Q. Does this conclude your testimony?

A. Yes.

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TESTIMONY OF

CARIE LEE, GERARD BOLDEN, RONALD HOMENICK, BYRON KEEP,
JOHN HAIRSTON, JANET ROSS KLIPPSTEIN, AND STEPHANIE KONESKY

Witnesses for Bonneville Power Administration

SUBJECT: SLICE REVENUE REQUIREMENT AND RATE

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TESTIMONY OF

CARIE LEE, GERARD BOLDEN, RONALD HOMENICK, BYRON KEEP, JOHN HAIRSTON, JANET ROSS KLIPPSTEIN, AND STEPHANIE KONESKY

Witnesses for Bonneville Power Administration

SUBJECT: SLICE REVENUE REQUIREMENT AND RATE

Section 1. Introduction And Purpose Of Testimony

Q. Please state your names and qualifications.

A. My name is Carie Lee and my qualifications are contained in WP-07-Q-BPA-28.

A. My name is Gerard Bolden and my qualifications are contained in WP-07-Q-BPA-05.

A. My name is Ronald Homenick and my qualifications are contained in WP-07-Q-BPA-17.

A. My name is Byron Keep and my qualifications are contained in WP-07-Q-BPA-22.

A. My name is John Hairston and my qualifications are contained in WP-07-Q-BPA-15.

A. My name is Janet Ross Klippstein and my qualifications are contained in WP-07-Q-BPA-25.

A. My name is Stephanie Konesky and my qualifications are contained in WP-07-Q-BPA-26.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to describe the elements of the Slice Revenue Requirement and the applicable Slice rate for FY 2007-2009. Also, the purpose of this testimony is to sponsor portions of the Wholesale Power Rate Development Study (WPRDS) and the Wholesale Power Rate Schedule and General Rate Schedule Provisions (GRSPs) related to the Slice Revenue Requirement and Slice Rate.

Q. How is your testimony organized?

A. This testimony contains seven sections, including this introductory section. In Section

2, the testimony will describe the Slice product for background purposes. Section 3 provides a general description of the Slice Revenue Requirement. Section 4 describes the calculation of the Slice rate for FY 2007-2009. Section 5 describes the annual Slice True-Up process. Section 6 provides a discussion of the various categories of expenses and revenue credits included in the Slice Revenue Requirement that may require additional clarification with respect to their inclusion and treatment in the Slice Revenue Requirement and Actual Slice Revenue Requirement. Section 7 provides a discussion of the updates to the Methodology to Calculate Slice Rate and Slice True-Up Adjustment Charge. Table 1, Slice Product and Costing and True-Up Table, follows these sections.

Section 2. Background

Q. What is the Slice product?

A. The Slice product is a power sale, based upon a Slice customer's annual net firm requirements load and is shaped to BPA's generation from the Federal system resources. The Slice product includes both service to net requirements firm load as well as an advance sale of surplus power. Since the Slice product is shaped to BPA's generation from the Federal system resources, there is no assurance that the Slice customer's net requirements load will be met during any hour by the Slice product.

Q. How does BPA determine the amount that individual Slice customers pay for the Slice product?

A. Each Slice customer pays a percentage of the Slice Revenue Requirement, equal to the percentage of the generation output from Federal system resources that the Slice customer elected to purchase in its 10-year Subscription contract. BPA's WP-07 Wholesale Power Rate Case will establish the Slice Revenue Requirement for the sale of the Slice product during the FY 2007-2009 rate period.

Section 3. Slice Revenue Requirement

Q. What is the Slice Revenue Requirement?

A. The Slice Revenue Requirement is the list of the expenses and revenue credits used to calculate the Slice rate. The Slice Revenue Requirement includes the same expenses and revenue credits that are included in BPA's generation revenue requirement with certain limited exclusions. Table 1 following this testimony contains the Slice Revenue Requirement for the FY 2007–2009 rate period. This table will also update the Exhibit I in the Block and Slice Power Sales Agreement (Block/Slice PSA).

Q. What expenses and revenue credits are excluded from the Slice Revenue Requirement?

A. In general, there are three types of excluded expenses: (1) power purchases except those associated with the inventory solution; (2) inter-business line transmission costs (except those associated with serving BPA System Obligations and General Transfer Agreements (GTAs)); and (3) Planned Net Revenues for Risk (PNRR) (or its successor risk mitigation tools) and hedging expenses (except those hedging expenses associated with the inventory solution).

Q. Why are these expenses excluded from the Slice Revenue Requirement?

A. First, power purchase expenses are excluded from the Slice Revenue Requirement because Slice customers assume the power supply and market price risks directly. However, Slice customers are obligated to pay their share of any net power purchase expenses associated with BPA's inventory solution. Second, transmission expenses are excluded from the Slice Revenue Requirement because these expenses are associated with BPA's surplus power sales. Slice customers receive a share of surplus power directly through their purchase of the Slice product, and do not share in the expenses or revenues associated with BPA's surplus power sales. Third, Slice customers do not pay PNRR and hedging expenses because the Slice customers assume a commensurate share of BPA's financial risks by shifting power supply and market price risks directly to the

Slice customer. In addition, the Slice product incorporates an annual True-Up Adjustment Charge for the difference between planned and actual expenses and revenue credits of the Slice Revenue Requirement (*see,* Section 5 of this testimony for details on the True-Up process).

Q. What revenue credits are included in the Slice Revenue Requirement?

A. The revenue credits that are included in the Slice Revenue Requirement are, for the most part, the same credits that are included in the calculation of the PF rate. In general, the included revenue credits are those credits relevant to the expenses in the Slice Revenue Requirement. The revenue credits included in the Slice Revenue Requirement are shown in Table 1, Slice Product and Costing Table, lines 107 – 117. *See,* Section 6.10 of this testimony for details on the Operating Reserves Revenue Credit.

Q. What revenues are excluded from the Slice Revenue Requirement?

A. The Firm Power Products and Services (FPS) revenues and Green Tag revenues are excluded. FPS revenues are excluded because these are revenues associated with sales of power from BPA's share of the generation output from the Federal Columbia River Power System (FCRPS). Green Tag revenues are excluded because Slice customers did not purchase any of the "attributes" of power generated from renewable resources, though Slice customers receive a proportionate share of the generation output from renewable resources.

Section 4. Slice Rate

Q. What is the Slice rate?

A. The Slice rate is the monthly dollar amount that is charged to Slice customers per percent of Slice product purchased. The Slice Revenue Requirement is the basis for calculating the Slice rate.

Q. Is BPA proposing changes to the method used to calculate the Slice rate?

A. No.

Q. Please explain how the Slice rate is calculated.

A. To calculate the Slice rate, the total dollar amounts for each FY of the Slice Revenue Requirement are summed and divided by 36 months (the number of months in the three-year rate period FY 2007-2009) and divided by 100 to obtain the monthly base Slice rate per percent of Slice product purchased.

Q. How much is the monthly Slice rate per percent of Slice product purchased?

A. For the WP-07 initial proposal, the estimate of the monthly Slice rate is $1,892,726 per percent Slice product purchased.

Section 5. Slice True-Up

Q. What is the Slice True-Up?

A. The Slice True-Up is a process that ensures that Slice customers pay their share of PBL's actual expenses and receive their share of actual revenue credits.

Q. How does the True-Up process work?

A. The True-Up process works in the following manner. BPA calculates the difference between the Slice Revenue Requirement for the applicable Fiscal Year (FY) and the Actual Slice Revenue Requirement for that FY. The Actual Slice Revenue Requirement contains the final audited actual expenditures and revenues as reflected on BPA's Power Business Line (PBL) financial statements. The Actual Slice Revenue Requirement includes the same expense and revenue credit categories as the Slice Revenue Requirement.

(indent – there are no space between paragraphs) The value of the Actual Slice Revenue Requirement for a FY is subtracted from the value for the Slice Revenue Requirement for the same FY (*see,* Table 1, Slice Product Costing and True-Up Table, line 132). Any difference between the Actual Slice Revenue Requirement and the Slice Revenue Requirement is called the Slice True-Up Amount. A positive or negative result from the calculation will result in an additional charge or credit to the Slice customer.

Q. What other charges are included in the Slice customers' True-Up Adjustment Charge (or Credit)?

A. Other charges that are included in the Slice customers' True-Up Adjustment Charge (or Credit) are the Slice Implementation Costs for the FY. Slice Implementation Costs are those costs that are incurred by PBL during the FY for the sole purpose of implementing the Slice product, and which would not have been incurred had PBL not sold the Slice product. Slice customers, as a group, are responsible for paying 100 percent of these Implementation Costs after they are incurred by PBL, through their True-Up Adjustment Charge. All Slice Implementation Costs are accounted for as expenses in the Actual Slice Revenue Requirement.

Q. Is BPA proposing any changes to the True-Up process?

A. No.

Section 6. Inclusion and Treatment of Expenses and Revenue Credits

Section 6.1. Augmentation Expenses

Q. Please define augmentation.

A. In the WP-02 rate case, BPA took steps to supplement the capability of the Federal Base System (FBS) to meet the total load placed on BPA. Augmentation was defined as the power purchases that were needed, on a planning basis, to meet all load service requests made under BPA's Subscription contracts. Augmentation has been referred to as the "inventory solution" for purposes of the Slice product. For the WP-07 rate case, the term "augmentation" will be used instead of "inventory solution."

Q. What is the difference between augmentation purchases and "balancing purchases?"

A. Conceptually, augmentation purchases are separate and distinct from "balancing purchases." "Balancing purchases" refer to those purchases used to replace reduced hydro system flexibility due to operating constraints and to those purchases needed to serve BPA's load on an hourly and monthly basis. Slice customers do not pay for

BPA's "balancing purchases," as the Slice customers face the risk of reduced hydro system flexibility directly and have the obligation to serve their own loads on an hourly and monthly basis.

Q. What augmentation expenses are the Slice customers required to pay?

A. The WP-02 rate case established that the Slice customers would be required to pay their proportionate share of the net cost of all augmentation expenses.

Q. What does the "net cost" of augmentation mean for the Slice Revenue Requirement?

A. As established in the WP-02 rate case, the "net cost" of augmentation refers to the costs associated with the purchase of the augmentation power less the associated revenues from the sale of such augmentation power. Slice customers would not receive any power associated with augmentation purchases.

Q. Is BPA forecasting any augmentation expenses for the FY 2007–2009 rate period?

A. Yes. BPA will have three types of augmentation expenses in the FY 2007–2009 rate period. The three types of expenses include: 1) "residual" augmentation expenses; 2) "deferred" augmentation expenses; and 3) other augmentation expenses.

Q. What is a "residual" augmentation expense?

A. "Residual" augmentation expenses are the expenses associated with augmentation purchases that carried over from the FY 2002-2006 rate period into the FY 2007–2009 rate period. When BPA purchased power on the market to meet its load obligations for the FY 2002-2006 period, some of the purchases extended to the end of the 2006 calendar year, rather than ending at the close of the rate period (September 30, 2006). Had these augmentation expenses been incurred during the FY 2002-2006 rate period, Slice customers would have paid for these expenses through the Load-Based Cost Recovery Adjustment Clause (LB CRAC). However, the LB CRAC only collected augmentation expenses that were needed to meet BPA's load. To the extent that these augmentation purchases were not needed to meet BPA's load, the risks associated with these purchases are borne solely by BPA.

Q. Is any portion of the "residual" augmentation purchases necessary to meet BPA's load?

A. No. The MWs associated with the "residual" augmentation purchases are not needed to meet BPA's load.

Q. Is the "residual" augmentation expenses itemized in the Slice Revenue Requirement?

A. Yes. In the Slice Revenue Requirement,Table 1, Slice Product and Costing Table line 126 shows the "residual" augmentation expense for FY 2007 only, and amounts to $49.063 million.

Q. What is the net cost of this "residual" augmentation power?

A. The net cost of this "residual" augmentation power is assumed to be zero because the Slice customers will not be assessed any related charges. *See,* Table 1, Slice Product Costing and True-Up Table, line 128).

Q. Will this estimate of the net cost of the "residual" augmentation power be subject to the annual Slice True-Up?

A. No, this estimate of the net cost of the "residual" augmentation power will not be subject to the annual Slice True-Up.

Q. What are the "deferred" augmentation expenses?

A. "Deferred" augmentation expenses are those augmentation expenses incurred during the FY 2002–2006 rate period, but the payment of which is deferred to the FY 2007–2009 rate period and beyond. The "deferred" augmentation expenses are associated with payment of a "Reduction of Risk Discount" to Puget Sound Energy and PacifiCorp. The *Proposed Contracts or Amendments to Existing Contracts with the Regional Investor-Owned Utilities regarding the Payment of Residential and Small-Farm Consumer Benefits under the Residential Exchange Program Settlement Agreements FY 2007-2011 Administrator's Record of Decision* (May 25, 2004) (IOU Contract ROD) modified approximately $200 million in Reduction of Risk Discount payments to Puget Sound Energy (Puget) and PacifiCorp. The approximate $200 million Reduction of Risk Discount resulted from the Puget and PacifiCorp load reduction under their respective Residential Exchange Program (REP) Settlement Agreements. The contracted load reduction was part of BPA's overall augmentation strategy to meet BPA power obligations during the first five years of the Subscription contracts. In the contracts associated with the IOU Contract ROD, Puget and PacifiCorp agreed to forgo collection of one half of the Reduction of Risk Discount ($100 million) and deferred collection of the balance ($100 million) until the FY 2007-2011 period. With interest payments, this results in $115 million of deferred augmentation expenses for FY 2007-2011, and will be recovered through Priority Firm (PF) rates in amounts of approximately $23 million per year. Because these costs, like those related to the "residual" augmentation purchases, are augmentation costs that would have otherwise been paid by Slice and non-Slice customers through the LB CRAC, it is appropriate to include these costs in the Slice Revenue Requirement in order to avoid any cost shift between Slice and non-Slice customers.

Q. Has BPA re-characterized the $23 million since the close of the Power Function Review (PFR)?

A. Yes. Originally the PFR classified the $23 million as part of the payments under the REP Settlement Agreements. Since the PFR, BPA properly re-characterized the $23 million annual cost from the "Residential Exchange/IOU Settlement Benefits" forecast to the contracted power purchases category. *See,* Homenick*, et al.,* WP-07-E-BPA-10.

Q. Where are these "deferred" augmentation expenses reflected in the Slice Revenue Requirement?

A. These "deferred" augmentation expenses are reflected in line 124 of the Slice Revenue Requirement (*see,* Table 1, Slice Product Costing and True-Up Table, line 124).

Q. *Will Slice customers pay the "net cost" of these "deferred" augmentation expenses?*

A. No. Because these expenses have no power deliveries associated with them, there are no related revenues which would be used to calculate a "net cost." Therefore, for these expenses, Slice customers will pay their proportionate share of the gross annual expense. The gross annual expense is approximately $23 million during the FY 2007–2009 rate period.

Q. *Will these "deferred" expense estimates be subject to the annual Slice True-Up?*

A. No, these estimates will not be subject to the annual Slice True-Up, as they are set by contract and are not expected to change.

Q. *What "other" augmentation expenses are included in the Slice Revenue Requirement?*

A. The "other" augmentation expenses include the augmentation purchase expense that BPA is forecasting it will make to meet its load obligation during FY 2008–2009.

Q. *What is the aMW amount of these purchases?*

A. BPA is forecasting a need to augment the system during FY 2008 and FY 2009 for 38 aMW and 92 aMW, respectively. *See,* Hirsch, *et al.*, WP-07-E-BPA-09.

Q. *How will Slice customers pay for these augmentation purchases?*

A. Slice customers will pay their proportionate share of the "net cost" of these "other" augmentation purchases.

Q. *What assumptions underlie the "other" augmentation purchase expense?*

A. BPA assumes that it will purchase augmentation power in FY 2008 at 56 mills per kwh and at 54 mills per kWh in FY 2009. *See,* WPRDS Documentation, WP-07-E-BPA-05A, Table 3.6.2. and Wagner *et al.,* WP-07-E-BPA-12.

Q. *How are the revenues associated with the sale of "other" augmentation power in FY 2008–2009 calculated?*

A. For FY 2008–2009, the revenues associated with the sale of augmentation power are estimated, based on the projected PF rate for power and multiplied by the amount of power that will be sold (38 aMW and 92 aMW, respectively for FY 2008, FY 2009).

Q. What is the projected PF rate used to calculate the revenues associated with the sale of "other" augmentation power?

A. The projected PF rate for power is 31 mills per kWh.

Q. Will the net cost of augmentation for FY 2008–2009 be subject to the Slice True-Up process?

A. No. The net cost of augmentation for FY 2008–2009 will not be subject to the Slice True-Up process. However, if there are relevant updates to the assumptions used in calculating the net cost of augmentation between BPA's initial proposal and final proposal, the net cost of augmentation numbers will reflect those changes.

No space here – have Shirley fix

Section 6.2. Conservation Augmentation

Q. What was Conservation Augmentation (ConAug)?

A. ConAug was the conservation component of BPA's inventory solution in the WP-02 rate case. ConAug was a resource acquisition effort to purchase conservation measures to reduce BPA's load obligation.

Q. What ConAug costs were included in the Slice Revenue Requirement?

A. The annual costs of ConAug were estimated and included in the inventory solution (augmentation) for the FY 2002–2006 Slice Revenue Requirement. Since it was not known specifically during the WP-02 rate case how the ConAug program would be implemented, the annual costs were derived as if the load reduction was equivalent to a power purchase. The estimate of ConAug costs was based on the assumption that 20 aMW of ConAug would be purchased each year during the FY 2002–2006 rate period. The cost of this power was estimated to be 28.1 mills per kWh plus 10 percent, or 30.9 mills per kWh.

Q. *Were the ConAug costs subject to the Slice True-Up process?*

A. No. In the WP-02 rate case, BPA set the ConAug expense as a fixed amount that was not subject to the Slice True-Up. This fixed amount was limited to the first 20 aMW of ConAug acquired each year during the FY 2002–2006 rate period.

Q. *Did Slice customers pay their proportionate share of ConAug costs?*

A. Yes. Slice customers paid their share of the estimated costs of 100 aMW of ConAug because these costs were included in their Slice Revenue Requirement and base Slice rate during the FY 2002-2006 rate period. The cost of this 100 aMW was not subject to the Slice True-Up. If BPA acquired more than 20 aMW during any given year, those costs would be handled through LB CRAC and included in related charges to both Slice and non-Slice customers.

Q. *Are there any costs from ConAug acquisition in the FY 2002–2006 rate period that carry over into the FY 2007–2009 rate period?*

A. Yes. Since the costs of actual ConAug acquisitions were capitalized, there is annual amortization expense associated with ConAug investments from the FY 2002–2006 rate period that carry over into the FY 2007–2009 period. These investments are amortized over the term of the Subscription contracts and are not fully amortized until 2011.

Q. *Will Slice customers be required to pay for the ConAug amortization expense in the FY 2007–2009 rate period?*

A. No. Slice customers will not pay for ConAug amortization in the FY 2007-2009 rate period because Slice customers paid a forecast of ConAug costs as if they were incurred as annual expenses rather than capitalized investments. As a result, the amortization will be excluded from the Slice Revenue Requirement and the Actual Slice Revenue Requirement.

Q. *Will there be any further ConAug acquisitions in the FY 2007–2009 rate period?*

A. No. The ConAug program will end on September 30, 2006.

Q. Is there a successor to the ConAug program?

A. Yes, the ConAug program will be replaced by the Conservation Acquisition program. The costs of the Conservation Acquisition program are assumed to be capitalized and there is an annual amortization expense that is forecasted and included in the Slice Revenue Requirement for the FY 2007–2009 rate period.

Section 6.3. IOU Residential Exchange Program (REP) Settlement Benefits

Q. Will Slice customers pay their proportionate share of any IOU REP Settlement benefits payments to PNW IOUs under the IOU REP Settlement Agreements during the FY 2007–2009 rate period?

A. Yes. In the WP-02 rate case, BPA established that regardless of what the net cost of the settlement of the Residential Exchange Program was, Slice customers were responsible for their proportionate share of these costs through the annual Slice True-Up process. *See,* Mesa, *et al.*, WP-02-E-BPA-54, at 9, lines 13-22.

Q. What payments for IOU REP Settlement benefits will BPA make to the IOUs during the FY 2007–2009 rate period?

A. There are two aspects to the payments to the IOUs: (1) the balance of the FY 2003 $55 million payment deferral for all IOUs not repaid as of September 30, 2006 which results in an annual payment to the IOUs of $3.7 million over the five-year period beginning October 2006; and (2) IOU REP Settlement benefits to all six IOUs (Avista Corporation, Idaho Power Company, NorthWestern Energy Division of NorthWestern Corporation, Portland General Electric Company, PacifiCorp, and Puget Sound Energy) applied to the FY 2007–2011 period, specified under their contracts or contract amendments entitled, "Agreement Regarding Payment of Residential Exchange Program Settlement Benefits during FY 2007–2011."

Q. Explain the origins of the "balance of the FY 2003 $55 million payment deferral for all IOUs not repaid as of September 30, 2006."

A. In BPA's Financial Choices process, BPA made decisions to cut, eliminate, or defer certain costs. As part of Financial Choices, BPA sought to defer a portion of the financial benefits under the IOU REP Settlement Agreements. BPA viewed the deferral of these benefits as a tool to help avoid implementing a Safety Net CRAC (SN CRAC) adjustment to rates. Each IOU signed an "Agreement Regarding Fiscal Year 2003 Deferral Amount" that deferred payment to the IOUs of $55 million in FY 2003. Pursuant to those agreements, BPA would repay this debt with interest during FY 2004-2006 in the amounts equivalent to any SN CRAC imposed on the IOUs. The SN CRAC was applied to IOU REP Settlement benefits, Firm Power Sales, and Load Reductions in FY 2004 and FY 2006. Any balance still owed on September 30, 2006, would be repaid with interest over the subsequent 60-month period (FY 2007–2011).

Q. What is the amount of the remaining balance still owed on September 30, 2006?

A. The remaining balance still owed on September 30, 2006, will be $17.7 million.

Q. Will the balance still owed on September 30, 2006, be included as an expense in the Slice Revenue Requirement for the FY 2007–2009 period?

A. No, the entire $55 million was accounted for as an expense in FY 2003, and the Slice customers paid their proportionate share of this expense through the True-Up Adjustment in that year. The balance still owed on September 30, 2006, will not be included as an expense in the Slice Revenue Requirement for purposes of calculating the Slice rate, nor will it be accounted for as an expense in the Actual Slice Revenue Requirement for the FY 2007–2009 period for purposes of the annual Slice True-Up.

Q. How will the interest associated with the $55 million deferred payments be accounted for?

A. The interest associated with the $55 million currently is being accounted for as an expense in the Actual Slice Revenue Requirement for calculation of the True-Up Adjustment Charge during the FY 2002-2006 rate period. The interest is included in the

FY 2007–2009 Slice Revenue Requirement for purposes of calculating the Slice rate (*see* Table 1, Slice Product Costing and True-Up Table, line 87). The interest also will be accounted for as an expense in the Actual Slice Revenue Requirement for calculation of the True-Up Adjustment Charge in the FY 2007–2009 period. Currently, the interest is forecast to be approximately $1 million annually.

Q. Explain the "IOU REP Settlement benefits to all six IOUs."

A. In May 2004, all six IOUs signed contracts or contract amendments entitled, "Agreement Regarding Payment of Residential Exchange Program Settlement Benefits during FY 2007–2011." These contracts or contract amendments apply to the FY 2007–2011 period, and specify that BPA will provide monetary benefits rather than physical power to each of the six IOUs. The contracts or contract amendments also specify a mark-to-market methodology for determining the amount of the monetary benefits based upon the difference between a market price and the lowest-cost PF rate. *See,* Petty*, et al.,* WP-07-E-BPA-11.

Q. What is the amount of the IOU REP Settlement benefits to all six IOUs?

A. The amount of the IOU REP Settlement benefits payments to all six IOUs is not fixed but rather will change each year depending on the difference between an independent market price forecast and lowest-cost PF rate (including any CRAC or DDC). In addition to the new methodology, the FY 2007–2011 contracts or contract amendments provide both a cap and a floor for benefit levels. The IOU REP Settlement benefits to be paid by BPA during any fiscal year has a floor of $100 million and a cap set at $300 million. BPA currently is forecasting the benefit amount to be at or near the cap during the upcoming rate period.

Q. Will Slice customers pay their proportionate share of these IOU REP Settlement benefits payments?

A. Yes. Whatever the amount of IOU REP Settlement benefits payments, Slice customers will pay their proportionate share of these payments through the Slice Revenue Requirement, which will be subject to the annual Slice True-Up.

Section 6.4. Cost of the Residential Exchange for Public Utilities

Q. Will Slice customers pay their share of the costs of the Residential Exchange Program for public utilities?

A. Yes, whatever the costs of the Residential Exchange Program (REP) for public utilities are, Slice customers will pay their proportionate share of these costs.

Q. Are the costs of the REP for public utilities included in the Slice Revenue Requirement for the FY 2007–2009 period?

A. No. For the WP-07 Initial Proposal, BPA is not forecasting any REP costs for the public utilities. However, if the forecast for REP costs for public utilities changes in the WP-07 Final Proposal, such costs will be included in the Slice Revenue Requirement.

Q. Are these costs subject to the annual Slice True-Up?

A. Yes, the actual costs of the REP for public utilities in any year will be included in the Actual Slice Revenue Requirement for that year for purposes of calculating the Slice True-Up.

Section 6.5. Bad Debt Expense

Q. What is bad debt expense?

A. The expense associated with the Allowance for Uncollectible Receivables is also known as bad debt expense. Uncollectible receivables are a standard business expense across the industry and are a normal cost of doing business. Bad debt expense is an item in BPA's audited financial statements and is therefore part of the "final audited expenditures" which are included in the Actual Slice Revenue Requirement for the Slice True-Up.

Q. *Will Slice customers pay a proportionate share of BPA's bad debt expense?*

A. Yes. Through the annual Slice True-Up, Slice customers will pay their proportionate share of these expenses.

Q. *Does the Slice Revenue Requirement contain bad debt expense?*

A. Yes. The Slice Revenue Requirement contains a line item labeled, "Other Accounts." This line item contains the amounts associated with "Bad Debt Expense" and "Other Income, Expenses, and Adjustments," both of which are line items in PBL's Statement of Revenues and Expenses. While no amounts are forecasted for the FY 2007–2009 period, the compilation of the Actual Slice Revenue Requirement will contain whatever is accounted for in these accounts.

Q. *How does BPA determine how much bad debt expense there is in any given FY?*

A. BPA managers evaluate the probability of collection of receivables in any given year and determine what amounts would be recognized as an expense to be included in the Actual Slice Revenue Requirement for purposes of calculating the Slice True-Up in that year. These expenses are accounted for under Generally Accepted Accounting Principles (GAAP) in BPA's financial statements.

Q. *What if revenues are received in a FY that are related to the bad debt that had been expensed in a previous FY?*

A. Because the Slice customers paid their proportionate share of the bad debt expenses recognized by BPA in previous fiscal years, Slice customers will be credited for any incoming dollars that are associated with the reversal of previous write-offs of bad debt expenses.

Section 6.6. DSI Costs

Q. *What DSI costs will be included in the Slice Revenue Requirement?*

A. On June 30, 2005, BPA's Administrator signed the Record of Decision on *Service to Direct Service Industrial (DSI) Customers for Fiscal Years 2007–2011* (DSI ROD). In this decision, the Administrator determined that BPA would offer 560 aMW of service benefits to the aluminum smelters, capped at an annual cost of $59 million and 17 aMW to Port Townsend Paper Corporation for the FY 2007–2011 period. *See,* Gustafson, *et al.*, WP-07-E-BPA-17. These costs will be included in the Slice Revenue Requirement and will be subject to the annual Slice True-Up. In addition, the DSI ROD specifies that an "essential condition of this decision is that costs are shared among all Slice and non-Slice customers."

Q. Where are the DSI costs reflected in the Slice Revenue Requirement?

A. The DSI costs are reflected in the line item entitled "Other Accounts, including bad debt expense" (*see,* Table 1, Slice Product Costing and True-Up Table, line 79).

Section 6.7. Fish Program Costs

Q. Will Slice customers pay their proportionate share of BPA's direct program costs for fish and wildlife?

A. Slice customers will pay their proportionate share of BPA's direct program costs for fish and wildlife.

Q. Do Slice customers pay their proportionate share of BPA's indirect, or operational, program costs for fish and wildlife?

A. Yes. Indirect program costs include any effects on power generation due to operational changes to benefit fish and wildlife. Slice customers experience these effects directly, through reduced or changed Slice power deliveries.

Q. What if there are changes to the direct and indirect program costs for fish and wildlife, subsequent to the release of BPA's final rate proposal for FY 2007–2009?

A. If there are such changes, Slice customers would pay their proportionate share of any increase or decrease in direct program costs through their annual True-Up. Slice customers would be affected in real-time for any changes in indirect program costs for fish and wildlife, through changes in their Slice power deliveries.

Q. Will Slice customers be subject to the NMFS FCRPS BiOp Adjustment (NFB Adjustment) that works to mitigate the risks associated with certain fish and wildlife costs?

A. No. Slice customers will not be subject to the NFB Adjustment. Slice customers will pay their proportionate share of any changes in direct program costs through their annual True-Up, and, as mentioned previously, any indirect program cost changes (e.g., changed operations or increases in spill and flow) will be experienced through changes in Slice power deliveries.

Section 6.8. Slice Implementation Expenses

Q. What are Slice Implementation Expenses?

A. Slice Implementation Expenses are defined as those costs reasonably incurred by PBL in any Contract Year (same as BPA's FY) for the sole purpose of implementing the Slice product, and which would not have been incurred had PBL not sold Slice Output under the Block and Slice Power Sales Agreement.

Q. How are Slice customers charged for Slice Implementation Expenses?

A. If PBL incurs costs during any Contract Year for the purpose of implementing the Slice product, PBL will account for these as expenses and will charge 100 percent of these expenses to the Slice customers through the annual Slice True-Up.

Q. What is an example of a Slice Implementation Expense?

A. An example of a Slice Implementation Expense is any cost associated with the Slice Computer Application Project. Any costs associated with the Slice Computer Application Project incurred in any Contract Year would be accounted for as expenses, for purposes of the Slice True-Up.

Q. Why are Slice Computer Application Project costs accounted for as expenses, instead of capital costs?

A. Slice Computer Application Project costs are accounted for as expenses instead of capital costs, because the Slice Computer Application Project is similar in nature to those projects that are governed by BPA's Reimbursable or Project Funded In Advance (PFIA) agreement. Under either the Reimbursable or PFIA agreement, the cost of the project is fully charged to the non-BPA entity for whom the work was undertaken, no later than the completion of the project, in accordance with the language of these agreements. In addition, the cost of the project is fully charged to the non-BPA entity, regardless of whether or not BPA capitalized the project costs. The Slice Computer Application Project was developed for the sole purpose of implementing the Slice product and would not have been developed had it not been for the Slice product. Therefore, BPA will include 100 percent of Slice Computer Application Project costs in the Slice Implementation Expenses, regardless of whether or not these costs were capitalized.

Q. Are projections of Slice Implementation Expenses included in the Slice Revenue Requirement?

A. No. Projections of Slice Implementation Expenses are not included in the Slice Revenue Requirement, and therefore, are not included in the Slice rate. Slice Implementation Expenses in any given FY will be accounted for after the audited year-end Actual Slice Revenue Requirement for that FY is available. Slice Implementation expenses will be charged to Slice customers through the annual Slice True-Up for that FY.

Section 6.9. Debt Optimization Program

Q. What is the Debt Optimization program?

A. Essentially, through the Debt Optimization program, BPA refinances (extends the maturities of) Energy Northwest (EN) bonds as they come due and repays an equivalent amount of Federal debt instead. In total, the same amount of debt is repaid that rates were set to recover, but with an emphasis toward repaying Federal debt rather than nonfederal debt. *See,* Homenick, *et al.*, WP-07-E-BPA-10, Section 3.

Q Is a forecast of Debt Optimization included in the Slice Revenue Requirement for FYs 2007–2009?

A. No. Debt Optimization actions are not forecasted for rate setting. Only the Actual Slice Revenue Requirement manifests the effects of Debt Optimization transactions.

Q How is Debt Optimization reflected in the Actual Slice Revenue Requirement?

A. In any year in which Debt Optimization transactions occur, the debt service lines for the EN projects in the Actual Slice Revenue Requirement are reduced by the amount of principal that was extended and there is a corresponding increase in the repayment of Federal principal that is included in the Minimum Required Net Revenues calculation for the Slice True-Up (established in the May 2000 Administrator's Record of Decision, WP-02-A-02, at 16-20). In subsequent years, the interest component of the debt service lines for the EN projects in the Actual Slice Revenue Requirement is increased by the interest on the extended debt and the Federal net interest expense in the Actual Slice Revenue Requirement is lower by the interest on the additional Federal principal that was repaid. In addition, when Debt Optimization proceeds are applied to BPA's transmission bonds or appropriations through the extinguishing of PBL's cost recovery obligation for EN debt, that amount is recognized as "EN retired debt" in PBL's financial statements and included in the Actual Slice Revenue Requirement.

Q. How are the Debt Optimization transactions and their effects accounted for?

A. The financial effects from the refinancing and the related additional amortization of Federal debt are properly and fully accounted for in the Actual Slice Revenue Requirement, in accordance with the manner in which they are accounted for in PBL's statement of revenues and expenses and in the determination of business line financial reserves.

Q. Are non-Slice customers affected by the same factors?

A. Yes. The Debt Optimization program is a BPA debt management policy that not only affects the Slice rate (through the annual True-Up Adjustment Charge), but is a recognized factor of BPA's rate of general application through the implementation of Cost Recovery Adjustment Charge mechanisms (for example, the Financial-Based Cost Recovery Adjustment Charge in the WP-02 rates). Inclusion of the Debt Optimization program transactions in the annual True-Up Adjustment Charge is recognition of the Slice customers' share of these obligations.

Q. Are the Slice customers paying their proportionate share of the costs and receiving their proportionate share of the benefits related to the Debt Optimization program through the annual True-Up Adjustment Charge?

A. Yes. As long as the Slice True-Up recognizes all of the elements listed above, the Slice customers are paying their proportionate share of the increased cost elements and receiving their proportionate share of the decreased cost elements related to the Debt Optimization program.

Q. What if the annual True-Up Adjustment Charge did not include or properly reflect all of the elements related to the Debt Optimization program?

A. If the Slice True-Up recognized only the reduction in EN debt service, for example, and not the equivalent amount of cash used to repay Federal debt (through the Minimum Required Net Revenue calculation), the recovery of this repayment of Federal debt would be borne entirely by the non-Slice customers. This would not be equitable.

Section 6.10. Operating Reserves Revenue Credit

Q. What is the Operating Reserves revenue credit?

A. This revenue credit is associated with payments from BPA's Transmission Business Line (TBL) to PBL for PBL-supplied generation inputs for Operating Reserves. TBL receives revenue from transmission customers who purchase Operating Reserves from TBL to meet their reserve obligation to the BPA control area. A portion of the revenues collected from these customers is paid to PBL for PBL-supplied generation inputs. *See,* Bermejo, *et al.,* WP-07-E-BPA-20.

Q. Describe the revenues from TBL for PBL's supply of Operating Reserves.

A. The revenues associated with TBL's payments to PBL for Operating Reserves is projected to be approximately $35.08 million in each year of the FY 2007–2009 period. This revenue is forecasted from PBL's estimated annual average reserve obligation amount multiplied by the generation input rate for Operating Reserves demand across the rate period. In the WP-02 rate case, this amount was projected to be about $35 million in the FY 2002–2006 rate period. This amount was included in the Slice Revenue Requirement, as part of the Ancillary and Reserves Services revenue credit (*see*, Table 1, Slice Product Costing and True-Up Table, line 107). In the WP-07 Initial Proposal, BPA proposes to remove the component of the Ancillary and Reserves Services revenue credit associated with TBL payments to PBL for Operating Reserves. This change is needed because, since the WP-02 rate case, Slice customers and non-Slice customers have exercised their right to self-supply their Operating Reserves or supply Operating Reserves through third parties. The Ancillary and Reserve Services revenue credit was meant to reimburse those customers who purchased their Operating Reserves from BPA's TBL. With the advent of self-supply or third-party supply of Operating Reserves, providing a revenue credit for Operating Reserves is no longer applicable to those customers who self-supply or who self-supply through third parties. Any Slice customer who elects to purchase Operating Reserves from BPA's TBL that are supported from generation inputs provided by PBL will receive a credit that corresponds to the revenues PBL receives from that customer for Operating Reserves from TBL. *See,* Bolden, *et al.,* WP-07-E-BPA-13 and Bermejo, *et al.,* WP-07-E-BPA-20 for further explanation for the change in the allocation of the Operating Reserve revenue credit.

Section 7. Methodology to Calculate Slice Rate and Slice True-Up Adjustment

Q. Is BPA proposing to update the Methodology to Calculate Slice Rate and Slice True-Up Adjustment (Slice Rate Methodology) in the WP-07 proceeding?

A. Yes. BPA is proposing to make several minor updates to the Slice Rate Methodology to avoid confusion during the FY 2007–2009 rate period. These updates are intended to account for changes in circumstances since the Slice Rate Methodology was initially established and are not intended to materially change the Slice Rate Methodology.

Q. Please identify the proposed updates.

A. (1) Section 3 of the Slice Rate Methodology defines Contracted Loads and Forecasted Loads for "each five-year rate period shall be the average of five forecasted Fiscal Year loads…" When the Slice Rate Methodology was initially drafted, BPA anticipated two five-year rate periods. Because the proposed rate period is three years in duration and not five years, BPA is proposing to clarify the definitions so that each would read as follows: "each rate period shall be the average of the forecasted Fiscal Year loads for such rate period."

(2) In Section 4.A., the last sentence of the first paragraph contains language that specifies that "the monthly rate for the Slice product will be adjusted by the application of the Load-Based Cost Recovery Adjustment Clause…" This sentence will be deleted and replaced by the following sentence: "The monthly Expedited Bills for the Slice product will be adjusted by the true-up of the Load-Based Cost Recovery Adjustment Clause for FY 2007."

(3) In Section 4.A., the first sentence in the third paragraph reads as follows: "For the FY 2007–2011 rate period…" BPA is proposing to change the reference to the "FY 2007–2009 rate period." It is anticipated that a similar change will be necessary when BPA resets rates for the FY 2010-2011 period.

(4) In Section 4.B.1., the first sentence reads as follows: "The Slice Revenue

Requirement is a five-year annual average amount…" BPA is proposing to change the sentence to read: "The Slice Revenue Requirement is a three-year annual average amount…"

(5) Section 4. B. 6 will be updated to account for the different adjustments that are proposed for the FY 2007–2009 rate period. It will now read as follows:

> "6. Inapplicability of Cost Recovery Adjustment Clause (CRAC), the National Marine Fisheries Service, Federal Columbia River Power System, Biological Opinion Adjustment (NFB Adjustment), Targeted Adjustment Clause (TAC) and the Dividend Distribution Clause (DDC).
>
> Neither the Slice Rate nor the Slice True-Up Adjustment Charge paid by Slice purchasers will be subject to the CRAC, NFB Adjustment, the TAC, or the DDC identified in the WP-07 GRSPs or any successors thereto."

(6) Section 4.B.7 deals with the application of the LB CRAC, and it will be revised to account for the fact that there will be no LB CRAC in the next rate period only an LB CRAC true-up in FY 2007. It will now read as follows: "For FY 2007, the LB CRAC true-up will apply to the Slice Expedited Bills."

(7) Section 4.B.8 will be revised to account for changes in the rate period. The reference to the "Slice Revenue Requirement for FY 2002-2006" will be updated to the "Slice Revenue Requirement for FY 2007–2009."

(8) In Section 4.B.8, the last sentence that reads: "An additional adjustment is included in the Actual Slice Revenue Requirement…" This sentence will be deleted because it is not applicable.

(9) Section 4.D. that addresses the IOU Settlement Charge will be deleted because it is not applicable to the Slice Rate or Slice True-Up during the FY 2007–2009 rate period.

Q. Does this conclude your testimony?

A. Yes.

Table 1, Slice Product Costing and True-Up Table

				Audited Actual Data	2007 forecast	2008 forecast	2009 forecast
1	**PBL Costs ($000)**						
2	**GENERATION COSTS**						
3	Federal Base System						
4	Hydro						
5	Upstream benefits (PNCA headwater benefits)		11		1,714	1,714	1,714
6	Corps of Engineers O&M		6		161,519	165,742	170,407
7	Corps Depreciation		25				
8	U.S. Fish & Wildlife O&M		8		18,600	19,500	20,400
9	U.S. Fish & Wildlife Depreciation		25				
10	Bureau of Reclamation O&M		6		71,654	74,760	77,766
11	Bureau Depreciation		25				
12	Colville Settlement		6		16,968	17,354	17,749
13	Spokane Settlement				0	0	0
14	Packwood Dam		6				
15	**Subtotal**				**270,455**	**279,070**	**288,036**
16	Fish and Wildlife						
17	Expense, including Environmental Requirements		30		143,500	143,500	143,500
18	Amortization		26				
19	**Subtotal**				**143,500**	**143,500**	**143,500**
20	Trojan						
21	Decommissioning		22		9,300	5,200	2,200
22	Debt Service		21		8,605	7,888	0
23	**Subtotal**				**17,905**	**13,088**	**2,200**
24	WNP #1						
25	O&M WNP 1 & 3		22		50	52	54
26	Debt Service, includes Reassignment		21		160,673	168,644	166,011
27	**Subtotal**				**160,723**	**168,696**	**166,065**
28	WNP #2						
29	O&M/Capital Requirements		6		256,300	206,300	238,800
30	Debt Service		21		254,455	237,858	259,072
31	**Subtotal**				**510,755**	**444,158**	**497,872**
32	WNP #3						
33							
34	LIBOR interest rate swap				0	0	0
35	Debt Service		21		160,848	161,088	153,997
36	**Total**				**1,264,186**	**1,209,600**	**1,251,670**
37							
38	New Resources						
39	Idaho Falls		6				
40	Idaho Falls Debt Service		21				
41	Cowlitz+ Emerald		6				
42	Cowlitz+ Emerald Debt Service		21		11,619	13,247	13,739
43	Firm Purchased Power						
44	Competitive Acquisitions		6				
45	Columbia Hills (CARES)						
46	Wheeling Power Purchase		6				
47	Other Acquisitions						
48	**Total**				**11,619**	**13,247**	**13,739**
49							
50	Legacy Conservation						
51	Conservation expense	#	29		29,488	28,650	28,387
52	Generation Billing Credits		6				
53	Conservation Financing		21		5,203	5,198	5,196
54	Conservation Amortization		26				
55	**Total**				**34,691**	**33,848**	**33,583**
56	Energy Services Business		7		12,885	12,908	12,933
57	Other Generation Costs						
58	BPA Programs						
59	PBL Efficiencies		6		1,553	1,584	1,616
60	telemetering				200	200	200
61	Power Marketing		10		27,421	28,136	28,942
62	Other Power Marketing expenses						
63	PBL Salary Costs Mrktg, transm acqu, risk analys				-5,360	-5,360	-5,360
64	Power Scheduling		9		14,115	14,570	15,040
65	Inventory Solution Hedging Activities						
66	Generation Oversight		6		6,049	6,165	6,286
67	Administrative & Support Services	12	14		50,615	52,127	52,144
68	CSRS				10,550	9,000	15,375
69	Power Planning Council		30		9,085	9,276	9,467
70	Miscellaneous Depreciation		24		111,269	112,762	114,773
71	Miscellaneous Amortization				55,262	59,936	64,866

Table 1, continued, Slice Product Costing and True-Up Table

72	Geothermal Demonstration	29				
73	Renewables	29	26,214	32,143	55,356	
74	Long-term Generating Projects		24,666	25,054	25,452	
75	Contingency Resources					
76	Net Interest Expense	31	179,504	188,406	196,646	
77	Between Business Line Expense					
78	Other Projects					
79	Other Accounts, including Bad Debt expense	27	59,000	59,000	59,000	
80	WNP #3 Plant					
81	**Total Other Generation Costs**		**583,028**	**605,906**	**652,737**	
82	**Minimum Required Net Revenues**		**34,105**	**42,876**	**27,599**	
83	**COSA Table Subtotal**		**1,927,630**	**1,905,477**	**1,979,328**	
84						
85	**PBL Costs ($000)**					
86	Net Residential Exchange Costs					
87	Subscription Settlement Costs		301,000	301,000	301,000	
88	CEA Transmission Costs		24,806	25,550	26,991	
89	Ancillary and Reserve Service Costs	10	8,462	8,462	8,462	
90	PBL PF Trans. Pass-Through Costs					
91	PNCA & NTS Transmission Costs	9	1,775	1,825	1,875	
92	Other System Obligations Net Costs					
93	General Transfer Agreement Costs	10	47,000	47,000	48,000	
94	**REVENUE REQUIREMENT CHECK**		**2,310,673**	**2,289,314**	**2,365,656**	
95						
96	Individual Charges & Credits					
97	PF Conservation and Renewables Credit Costs		42,000	42,000	42,000	
98	IP Conservation and Renewables Credit Costs					
99	RL Conservation and Renewables Credit Costs					
100	LDD		18,000	18,000	18,000	
101	Irrigation Rate Mitigation Costs		12,000	12,000	12,000	
102	**Non-COSA Table Subtotal**		72,000	72,000	72,000	
103						
104	**Total PBL Revenue Requirement**		**2,382,673**	**2,361,314**	**2,437,656**	
105						
106	**Revenue Credits ($000)**					
107	Ancillary and Reserve Service Revs. Total		49,453	48,803	48,948	
108	PBL PF Trans. Pass-Through Revs.					
109	Canadian Entitlement Credit					
110						
111	COE & USBR Project Revenues		3,600	3,600	3,600	
112	4(h)(10)(c)		79,117	75,844	72,457	
113	Colville Credit		4,600	4,600	4,600	
114	FCCF					
115	Sup/Ent Cap; Irr. Pump		5,321	5,321	5,321	
116	Energy Efficiency Revenues		12,800	12,800	12,800	
117	Property Trnfrs & Misc.		3,420	3,420	3,420	
118						
119	**Total Revenue Credits**		**158,311**	**154,388**	**151,146**	
120						
121	**Power Revenues Needed**		**2,224,363**	**2,206,926**	**2,286,511**	
122						
123	**Augmentation Costs**					
124	**IOU Reduction of Risk Discount (includes interest)**		23,000	23,000	23,000	
125	**Costs in this box are not subject to True-Up**					
126	**Forecasted Gross Augmentation Costs**		49,063	18,626	43,721	
127	(Gross power purchase cost)					
128	Minus revenues		49,063	10,348	24,984	
129	**Net Cost of Augmentation**		**23,000**	**31,278**	**41,737**	
130						
131	**SLICE TRUE-UP ADJUSTMENT CALCULATION**					**3-Year Total Slice Rev. Reqt.**
132	**Annual Slice Revenue Requirement (Amounts for each FY)**		**2,247,363**	**2,238,204**	**2,328,248**	**$ 6,813,815**
133	**TRUE UP AMOUNT (Diff. between actuals and forecast)**					
134	**AMOUNT BILLED (22.6278 percent)**					
135	Slice Implementation Expenses (not incl. in base rate)		**2,300**	**2,300**	**2,300**	
136	**TRUE UP ADJUSTMENT**					
137						
138						
139	**SLICE RATE CALCULATION ($)**					
140	**Monthly Slice Revenue Requirement (3-Year total divided by 36 months)**					**$ 189,272,634.64**
141	**One Percent of Monthly Requirement (Slice Rate per percent Slice - Monthly Slice Revenue Requirement divided by 100)**					**$ 1,892,726.35**
142						
143	**ANNUAL BASE SLICE REVENUES**					**$ 513,938,798.66**
144	**Annual Slice Implementation Expenses**					**$ 2,300,000.00**
145	**TOTAL ANNUAL SLICE REVENUES**					**$ 516,238,798.66**
146						

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TESTIMONY OF

JOHN B. PYRCH, KAREN L. MEADOWS, MARK E. JOHNSON, KEN M. KEATING,

DEBRA J. MALIN, AND ALLAN E. INGRAM

Witnesses for Bonneville Power Administration

SUBJECT: CONSERVATION PROGRAMS AND CONSERVATION RATE CREDIT

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TESTIMONY OF

JOHN B. PYRCH, KAREN L. MEADOWS, MARK E. JOHNSON, KEN M. KEATING, DEBRA J. MALIN, and ALLAN E. INGRAM

Witnesses for Bonneville Power Administration

SUBJECT: CONSERVATION PROGRAMS AND CONSERVATION RATE CREDIT

Section 1. Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is John B. Pyrch and my qualifications are contained in WP-07-Q-BPA-46.

A. My name is Karen L. Meadows and my qualifications are contained in WP-07-Q-BPA-39.

A. My name is Mark E. Johnson and my qualifications are contained in WP-07-Q-BPA-20.

A. My name is Ken M. Keating and my qualifications are contained in WP-07-Q-BPA-21.

A. My name is Debra J. Malin and my qualifications are contained in WP-07-Q-BPA-35.

A. My name is Allan E. Ingram and my qualifications are contained in WP-07-Q-BPA-18.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to sponsor the Conservation Rate Credit (CRC) with renewable option, associated General Rate Schedule Provisions and those sections of the Wholesale Power Rate Development Study, Chapter 2.11 and Documentation for the Wholesale Power Rate Development Study, including Chapter 4.10 that address the CRC.

Q. How is your testimony organized?

A. This testimony consists of four sections including this introductory section. Section 2 explains how the Bonneville Power Administration (BPA) is implementing its Near-Term Policy for Power Supply Role for Fiscal Years 2007-2011 (Near-Term Policy) through the Final Post-2006 Conservation Program Structure to support the regional development of cost-effective conservation in the firm power customer loads supplied by BPA. Section 3 describes and explains the CRC, including the amount of the CRC, and eligibility and participation in the CRC. Section 4 describes the renewables option of the CRC.

Section 2. Ensuring Regional Development of Cost-Effective Conservation

Q. BPA issued the Near-Term Policy on February 4, 2005, and the Final Post-2006 Conservation Program Structure on June 28, 2005. What guidance do these policies provide for BPA's conservation program for this rate period?

A. The Final Post-2006 Conservation Program Structure adopted 5 principles to guide the development of BPA's acquisition programs in the post-2006 period. These principles are:

1. BPA will use the Northwest Power and Conservation Council's (Council) 5th Power Plan to identify the regional cost-effective conservation targets upon which the agency's share (approximately 40 percent) of cost-effective conservation is based.

2. The bulk of the conservation to be achieved is best pursued and achieved at the local level. There are some initiatives that are best served by regional approaches (for example, market transformation through the Northwest Energy Efficiency Alliance). The knowledge that local utilities have of their consumers and their needs reinforces many of the successful energy efficiency programs being delivered today.

3. BPA will seek to meet its conservation goals at the lowest possible cost to BPA. While only cost-effective measures and programs are a given, the region can benefit by working together to jointly drive down the cost of acquiring those resources.

4. BPA will continue to provide an appropriate level of funding for local administrative support to plan and implement conservation programs.

5. BPA will continue to provide an appropriate level of funding for education, outreach, and low-income weatherization.

Q. In its Final Post-2006 Conservation Program Structure of June 28, 2005, BPA states that *it has a strategic objective to ensure development of all cost- effective energy efficiency in the loads BPA serves and to facilitate development of regional renewable resources. How will the CRC and its underlying programs serve to meet this objective?*

A. The WP-07 Initial Proposal, BPA includes the CRC to encourage the regional development of incremental energy efficiency gains and renewable resources by BPA's customers. BPA is cognizant that this objective strives to capture all cost-effective conservation in those customer loads supplied by BPA. With that in mind, BPA has developed a mechanism to allow BPA's customers to design conservation and renewable resource programs that best meet their needs, while meeting regional cost effectiveness standards as developed by the Council. In addition, BPA proposes to continue its support for market transformation activities through the Northwest Energy Alliance and programs for utility, federal agency and bilateral conservation acquisition contracts. BPA believes that the combination of these activities will enable BPA to achieve its 52 aMW annual conservation target, which will help ensure we meet our strategic objective.

Q. Why does BPA believe it is important to encourage cost-effective conservation resource development?

A. BPA is directed by the Northwest Power Act to encourage the development of cost-effective conservation resources. Historically, BPA has met this directive through centralized conservation acquisition programs. Conservation is recognized as a resource that is used to meet regional firm power load. In the WP-02 rate case BPA sought to encourage its customers to develop conservation by proposing and establishing the Conservation and Renewables Discount (C&RD) as a new approach to providing incentives to customers to develop conservation and renewable resources. At the same time BPA is guided by the Council's power plans. The Council's recently published 5th Power Plan establishes new conservation targets for BPA. We believe the proposed CRC and post-2006 conservation program provides a proper level of encouragement to develop conservation in the region, consistent with the plan's target.

Q. Do you believe the CRC and Post-2006 Program Structure will encourage regional conservation development?

A. Yes we do. It is important to note that BPA developed its post-2006 conservation approach with the active participation of its customers, Council staff, and interested non-customer stakeholders. Based on the input from these sources BPA believes the CRC and post-2006 program will achieve our conservation goal.

Section 3. The Conservation Rate Credit

Q. Please describe the Conservation Rate Credit (CRC).

A. The proposed CRC is intended to replace the currently C&RD. The concept for a conservation rate credit is based on a recommendation made in the Comprehensive Review of the Northwest Energy System final report. Like the C&RD, the CRC will take the form of a credit on a customer's monthly power bill. It is a discount on the firm power rate available to customers purchasing under the PF-07, NR-07, and IP-07 rate schedules. Acceptance of the credit creates an incentive and responsibility for customers to develop and acquire conservation and renewable resources.

Q. Is the CRC related to the conservation surcharge mechanism included in the Northwest Power Act?

A. No. The CRC is not related to the conservation surcharge that the Administrator may impose as provided in §4(f)(2) of the Northwest Power Act. Unlike the CRC, a conservation surcharge may be established based on a recommendation made by the Council to recover costs within states or political subdivisions which have not implemented conservation measures.

Q. Would BPA impose a conservation surcharge, if recommended by the Council?

A. Pursuant to § 4(f)(2), the Administrator may choose to impose a surcharge based upon a recommendation of the Council to do so. The Council has not made such a recommendation. Therefore, we cannot say whether or not BPA would impose a conservation surcharge without viewing the underlying reasons for one.

Q. *Please describe in detail how the CRC will be reflected on the customers' power bills?*

A. The CRC will be billed as a line item reduction in the customer's monthly power bill. Customers are familiar with this method because it is the approach used for the current C&RD. The monthly CRC amount will be set prior to the rate period based on each customer's forecast average net requirements. The CRC will be deducted as a dollar amount and will not affect calculation of other billing factors.

Q. *What is the amount of the CRC?*

A. $0.50 per MWh of forecasted average net requirements made under the PF-07, NR-07 and IP-07 rate schedules.

Q. *How was the amount of the CRC derived?*

A. The $0.50 per MWh amount of the CRC is proposed based on the successful implementation of the C&RD. Customer feedback strongly supports continuation of the $0.50 per MWh amount and it is a reasonable amount to support BPA's long term goal of stable conservation funding over time.

Q. *Why was a specific amount chosen?*

A. A specific charge per MWh applied to a customers' forecasted Subscription power purchases will allow them to prepare fixed annual budgets for conservation and renewables expenditures that are equal to their eligibility for the CRC. Use of this method also allows for simplified billing procedures.

Q. *Will the CRC amount be applied to forecasted or actual loads?*

A. The CRC will be applied to forecasted loads. Specifically, the CRC will apply as follows: for slice customers it will be based on their individual percentage of the critical system annual amount of 7070 aMW. For other customers BPA will use the forecast average net requirements for the rate period to determine each customer's CRC eligibility. The use of actual loads would have made the CRC amount difficult to segregate for billing purposes. The actual CRC would vary by month and would be subject to revision in situations where bills must be estimated or corrected. Low Density Discount calculations would also be complicated by monthly adjustments.

Q. Are there energy savings attributed to the CRC?

A. The CRC, like the C&RD, is an alternative to centrally designed acquisition programs and the traditional conservation planning process. As part of a portfolio of conservation tools, the CRC is intended to encourage BPA customers themselves to make the actual conservation investment decisions. Therefore, the CRC is not designed to acquire conservation savings and thus no forecast of energy savings is included; however, based on our experience with the C&RD program energy savings are likely to be achieved. While BPA will not forecast such savings, BPA will include any and all conservation savings that are achieved through the CRC toward meeting BPA's conservation target of 52 aMW.

Q. Are customers who purchased under Pre-Subscription contracts eligible for the CRC?

A. Yes. Some Pre-Subscription contracts will have expired by the end of the FY 2002-2006 period and these customers will now receive power under subscription contracts. The addition of the loads previously served under pre-subscription contracts increased the total CRC cost by $6 million. Remaining Pre-Subscription contracts will be eligible for the CRC on a case-by-case basis through the life of their contract. Customer specific contract terms will determine the extent to which individual customers receive the CRC.

Q. Are investor-owned utility customers eligible for the CRC?

A. Yes. Investor-owned utility (IOU) customers purchasing power under the NR-07 rate schedule are eligible for the CRC. In addition, IOU customers with current exchange settlement contracts will also be eligible for the CRC under the terms of their contract and subject to the requirements of the CRC program. However, the PF Exchange Power

Rate does not include the CRC. Customers purchasing power under the PF Exchange Power rate are not eligible for the CRC. *See,* General Rate Schedule Provisions, WP-07-E-BPA-07 at 27.

Q. Why are IOUs under the PF exchange program eligible for the CRC?

A. The CRC is a new program that makes use of some of the principles from the C&RD. The exchange settlement contracts state that IOUs are eligible for any follow-on similar to the C&RD. The CRC is based on the C&RD program and is sufficiently similar to the C&RD to satisfy the IOU settlement exchange contract eligibility terms.

Q. Are direct-service industrial (DSI) customers eligible for the CRC?

A. Yes, DSIs purchasing firm power under the IP rate will be eligible to participate in the CRC. However, BPA is not expecting to sell firm power to any DSI under the IP rate during the rate period. Therefore, BPA expects zero DSI participation in the CRC.

Q. How will BPA determine whether the customer is participating in the CRC?

A. It is assumed that all eligible customers will participate in the CRC and this is reflected in the revenue forecast. The CRC will be reflected on all customers' bills automatically during the first year of the rate period. Actual participation will be determined, in the future, based on the actions the customer takes to implement or support conservation and renewable resources development in the region. Actions include activities or measures developed by the Regional Technical Forum (RTF) or other cost-effective measures as approved by BPA to qualify for the CRC.

Q. Can customers opt-out of the CRC?

A. Yes. Customers choosing to opt-out will not receive the CRC on their monthly bills and will therefore pay a rate of $0.50 per MWh higher than participating customers. Customers may elect not to receive the CRC monthly rate credit by providing written notice during the rate period. *See,* General Rate Schedule Provisions, WP-07-E-BPA-07 at 76.

Q. Are there any penalties if customers do not participate in qualified activities?

A. There are no penalties. However, utilities not qualifying for, or not participating in, the CRC will pay the posted rate without the CRC for BPA power purchases under their subscription contracts.

Section 4. Renewables Option

Q. What is the renewables option?

A. The renewables option under the CRC is intended to function like the "renewable" component did under the C&RD. Customers interested in pursuing renewable resource activities can elect to use a portion of the CRC for such purpose. Customers eligible for the CRC are automatically eligible for the renewables option.

Q. Why does BPA believe it is important to encourage renewable resource development?

A. One of BPA's purposes under the regional power act is to use the flexibility of the FCRPS to encourage renewable resource development within the region. BPA believes that the region will realize value through comparative energy costs and less pollution by providing incentives that encourage investments in renewable resources.

Q. What will be the benefits of providing a CRC renewables option?

A. BPA believes the renewables option will have the following benefits:

(1) Create a catalyst in furthering the region's public purposes goals;

(2) Increase renewable energy supplies within the region; and

(3) Reduce the amount of customer load placed on BPA.

Q. How much money is available under the renewables option?

A. Like the C&RD, the renewables option will make available to participating customers $6 million annually.

Q. How will money be apportioned among customers electing the renewables option?

A. Customers that elect to participate in the renewable option of the CRC will be required to declare their level of renewable resource activity three months prior to the beginning of each FY of the rate period. If the proposed renewables activity in aggregate exceeds the $6 million limit, customers participating in the option will receive a prorated reduction in their declared renewable resource activity.

Q. How will a prorated reduction in a customer's renewable resource activity affect their total CRC eligibility?

A. It will not affect a customer's total CRC eligibility. The *pro rata* reduction will only affect their ability to apply their eligibility towards renewables development activities.

Q. How will BPA monitor customer Renewable Option progress under the CRC?

A. Customers will be required to use the CRC Reporting Software to report their conservation activities. Customers will be required to submit progress reports every 6 months comparing their expenditures with their CRC declarations and eligibility. Customers whose progress reports indicate shortfalls will be required to prepare and implement an action plan, indicating how the utility will spend its rate credit funds by the end of the rate period. When the rate period expires, the customer is required to submit a final statement. Customers will be required to reimburse BPA money when qualifying CRC expenditures are less than the customer's CRC eligibility. *See,* General Rate Schedule Provisions, WP-07-E-BPA-07 at 75.

Q. Are Slice customers eligible for the renewables option of the CRC?

A. Yes.

Q. Does this conclude your testimony?

A. Yes.

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TESTIMONY OF

ALLAN E. INGRAM, DEBRA J. MALIN, AND ELLIOT E. MAINZER

Witnesses for Bonneville Power Administration

SUBJECT: FACILITATION FOR REGIONAL RENEWABLE RESOURCE DEVELOPMENT AND GREEN ENERGY PREMIUM

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TESTIMONY OF

ALLAN E. INGRAM, DEBRA J. MALIN, AND ELLIOT E. MAINZER

Witnesses for Bonneville Power Administration

SUBJECT: FACILITATION FOR REGIONAL RENEWABLE RESOURCE DEVELOPMENT AND GREEN ENERGY PREMIUM

Section 1. Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Allan E. Ingram and my qualifications are contained in WP-07-Q-BPA-18.

A. My name is Debra J. Malin and my qualifications are contained in WP-07-Q-BPA-35.

A. My name is Elliot E. Mainzer and my qualifications are contained in WP-07-Q-BPA-34.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to describe the Green Energy Premium (GEP).

Q. How is your testimony organized?

A. Our testimony includes three sections, including this introductory section. Section 2 explains how the Bonneville Power Administration (BPA) is implementing policy goals to provide facilitation and support for development of renewable energy resources. Section 3 describes the Green Energy Premium, why it is being proposed, and its implementation.

Section 2. BPA's Role as a Facilitator for Regional Renewable Resource Development

Q. The BPA Near-Term Policy for Power Supply Role for Fiscal Years 2007-2011 (Near-Term Policy) issued in February 2005 provides that BPA intends to act as a facilitator, encouraging the development of regional renewable resources during the FY 2007-2011 period. How does BPA intend to facilitate renewable resource development by its customers?

A. In the WP-07 Initial Proposal, BPA is proposing to replace the Conservation and

Renewable Rate Discount (C&RD) with the Conservation Rate Credit (CRC), which includes a renewables option. The renewables option is intended to incent incremental investment by BPA's customers in renewable energy resources. The renewables option is designed to assist power customers who desire to develop renewable resources and customer specific programs.

Q. Why does BPA believe it is important to facilitate renewable resource development?

A. One of BPA's purposes under the Regional Power Act is to use the flexibility of the FCRPS to encourage renewable resource development within the region. In addition, BPA believes the region should realize improved value through comparative energy costs and less pollution by providing incentives that encourage investments in renewable resources.

Q. How are you proposing to provide a renewable rate credit through the CRC renewable option?

A. BPA's Near-Term Policy included a CRC of $0.50 per megawatthour (MWh) for BPA customer purchases from selected rate schedules. The CRC is targeted toward qualifying conservation and renewable investments and includes a $6 million renewable option. The CRC includes the option to receive credit for renewable investments as well as conservation. The CRC program is discussed in the testimony of Pyrch *et al.*, WP-07-E-BPA-24.

Section 3. Green Energy Premium

Q. Please describe the Green Energy Premium (GEP).

A. The GEP is a dollar amount that is paid by customers choosing to purchase Environmentally Preferred Power (EPP) as part of their subscription power sales contract with BPA. As such it results in an adjustment to the customer's applicable firm power rate. Customers selecting the GEP will continue to receive system power deliveries from BPA. In addition, these customers will receive EPP production documentation showing that their GEP purchases represent production and delivery of EPP to the system. Those customers purchasing EPP will also receive documentation transferring renewable attributes from BPA to them.

Q. Why has the GEP been proposed in its current form?

A. BPA previously provided customers the opportunity to purchase EPP by applying the GEP. Based on customer demand BPA proposes to continue offering EPP and applying GEP.

Q. Is the GEP limited to Subscription requirements power purchases?

A. Yes. These purchases require a customer to commit a portion of its Subscription purchases, served at a posted requirements rate, to service at the posted rate plus the GEP. This is done by designating any portion of the customer's Subscription purchases as EPP. The GEP will be available to customer's purchasing power under the Priority Firm (PF-07), and New Resources (NR-07) rate schedules. Subject to the availability of surplus firm power, sales of EPP under the FPS-07 rate schedule may be offered in the future.

Q. Is there any limit to the amount of EPP that can be purchased under the GEP?

A. Yes. The amount of EPP subject to the GEP and available to individual customers is limited by the individual customer's Subscription requirements power purchases.

Q. How will BPA price the GEP?

A. The GEP will be negotiated and can range from zero to $40/MWh depending on BPA's inventory of renewable resource credits. The customer's power bill will have an additional line item showing the elected EPP energy amount in MWh times the GEP.

Q. Please describe the costs included in the GEP.

The negotiated GEP will be based on avoided cost and the market value of the non-power renewable attributes as well as applicable costs associated with the purchase. Such costs may include, but are not limited to:

- avoided costs of renewable energy credits based on existing BPA resources;

- avoided costs of renewable energy credits based on new or proposed BPA resources; and
- endorsement fees for specific EPP resources.

Q. Does the proposed GEP affect the determination of BPA's revenue requirement?

A. No. When the GEP is based upon existing BPA resources, BPA will incur no additional costs but will accrue additional revenues. BPA forecasts an average of $1.4 million of annual revenue from the GEP over the rate period.

Q. How will GEP revenue affect BPA renewable facilitation budgets?

A. Revenues from the GEP will support BPA renewable resource facilitation and research and development activities. While BPA is forecasting GEP revenue, it should be noted that if revenue is less than forecast the funding amounts available for the above activities will be correspondingly reduced. Consequently, BPA will not spend any GEP revenue until after the end of a fiscal year when such revenue is known.

Q. Does this end your testimony?

A. Yes

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TESTIMONY OF

ELLIOT MAINZER, GERY BOLDEN, CAROL A. MILLER,

AND PHILLIP MCLEOD

Witnesses for Bonneville Power Administration

SUBJECT: FIRM POWER PRODUCTS AND SERVICES (FPS) RATE SCHEDULE

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TESTIMONY OF

ELLIOT MAINZER, GERY BOLDEN, CAROL A. MILLER,

AND PHILLIP MCLEOD

Witnesses for Bonneville Power Administration

SUBJECT: FIRM POWER PRODUCTS AND SERVICES (FPS) RATE SCHEDULE

Section 1. Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Elliot E. Mainzer and my qualifications are contained in WP-07-Q-BPA-34.

A. My name is Gery Bolden and my qualifications are contained in WP-07-Q-BPA-05.

A. My name is Carol A. Miller and my qualifications are contained in WP-07-Q-BPA-40.

A. My name is Phillip W. McLeod and my qualifications are contained in WP-07-Q-BPA-38.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to describe rate design aspects and other relevant considerations that support BPA's proposed Firm Power Products and Services (FPS-07) rate schedule. In addition, this witness panel is sponsoring the FPS-07 rate schedule, associated General Rate Schedule Provisions (GRSPs), WP-07-E-BPA-07, at 55-62, and those sections of the Wholesale Power Rate Development Study (WPRDS), WP-07-E-BPA-05, at Chapter 6.4, and the WPRDS Documentation, WP-07-E-BPA-05B, that address the FPS-07 rate schedule and the products and services offered under that rate schedule.

Q. How is your testimony organized?

A. Our testimony is divided into eight sections, including this introductory section. Witnesses Mainzer, Bolden, and Miller are testifying to all sections, except for Section 7, which deals with the Market Power Study. Witness McLeod is testifying to Section 7 only. Section 2 discusses the purpose and historical background behind the proposed FPS-07 rate schedule. Section 3 outlines policy and objectives of firm power marketing for the FPS-07 Rate Schedule. Section 4 details relevant changes in BPA's position in the West Coast wholesale power market since 1996. Section 5 describes the proposed rate design, and Section 6 sets forth the term of the proposed FPS-07 rate schedule. Section 7 summarizes the methodology and findings of the Market Power Study. Finally, Section 8 sets forth BPA's proposal to eliminate the NF-02 rate.

Section 2. Purpose and Historical Background to FPS-07

Q. In general, as compared to BPA's other power rate schedules, how is the proposed FPS-07 rate different?

A. The proposed FPS-07 rate schedule is a market-based rate; BPA's other power rate schedules are cost-based.

Q. Does BPA currently have a rate schedule similar to the proposed FPS-07?

A. Yes. The FPS-96R rate schedule is a flexible rate designed to help BPA recover its costs by permitting BPA to sell power at negotiated rates in the wholesale electricity market. However, implementation of the FPS-96R rate schedule has been constrained by a settlement that BPA entered into for the 10-year term of FPS-96 (which was FPS-96R's predecessor rate schedule). BPA entered into the settlement after the close of the formal WP-96 7(i) rate making process and agreed to a cap on how much it would charge for firm power and a cap on how much it would charge per kilowatt-month for firm capacity. The cap levels were based on the costs of BPA's highest-cost resource (which were already established in the 7(i) record).

Q. Are any such constraints proposed for implementation of the FPS-07 rate schedule?

A. No. BPA is not proposing to place constraints on implementation of the FPS-07 rate schedule, such as those the settlement placed on the FPS-96 and FPS-96R rate schedules. As will be discussed in further detail in Section 4, the West Coast wholesale energy market has become more liquid and contains many more participants than in 1996; moreover, in the upcoming rate period BPA will have a much more limited amount of surplus energy than it expected to have when it first proposed the FPS-96 rate schedule. Accordingly, the rationale that gave rise to the constraints imposed by the settlement is no longer valid and it is therefore unnecessary to place similar restrictions on the FPS-07 rate schedule.

Q. What is the purpose behind BPA developing and proposing the FPS-07 rate schedule?

A. BPA developed the FPS-07 rate schedule to replace the FPS-96R rate schedule which expires on September 30, 2006. As with the FPS-96R rate schedule, BPA's overall objective of the FPS-07 rate schedule is to provide BPA with a degree of flexibility so that it can effectively market surplus firm energy from the Federal Columbia River Power System (FCRPS) in the West Coast wholesale energy market.

Factors such as weather, time of year, and fish and wildlife constraints cause generation levels available from BPA's hydro-based system to vary widely from year-to-year, month-to-month and even day-to-day. In addition to this wide variation in BPA's surplus energy amounts, BPA must manage variations in load. As a consequence of these competing factors, BPA must routinely participate in the West Coast wholesale market - both selling power when a surplus exists, and buying to make up any shortfalls.

Since BPA periodically finds itself purchasing power in the West Coast wholesale market to manage deficits, it is imperative that BPA also be able to sell at the going price in that same wholesale market. In order for BPA to avoid "buying high and selling low," FPS-07 must be a true market-based rate schedule that is not constrained by cost-based limitations. As contemplated in the FPS-07 rate schedule proposal, this flexible rate schedule will allow BPA to sell energy at negotiated rates to better manage risks inherent in recovering the Agency's costs and, at the same time, allow BPA to keep rates as low as possible for our preference customers.

Q. How does the proposed FPS-07 rate schedule fit within BPA's statutory objectives?

A. BPA's core statutory objectives include encouraging the widest possible diversified use of Federal power at the lowest cost consistent with sound business principles, to ensure preference and priority to public and cooperative systems, to secure the full repayment of the reimbursable portion of the Federal investment in the FCRPS, and to establish its rates to recover its costs from ratepayers.

At least as early as the 1987 Wholesale Power and Transmission Rate Proceeding (WP-87), the Administrator concluded that he had the authority to establish a type of market-based rate. *See,* WP-87-A-02, at 242-251 (discussing the Market Transmission rate, MT-87). Later, in the WP-96 rate case, BPA pointed out that section 7(e) of the Northwest Power Act grants the Administrator considerable rate design discretion, including the ability to employ rate designs that use a market-based approach. *See,* WP-96-A-02, at 457. The Agency further found that section 7(e) and its legislative history make clear that BPA's cost allocation directives concern the amount of revenues to be recovered from customer classes, and not the design of the rates to recover those revenues. *Id.* at 458. Therefore, in the aggregate, BPA's rates must be, and are, designed to recover BPA's total costs.

The proposed FPS-07 rate schedule, like its predecessors the FPS-96 and FPS-96R rate schedules, provides BPA with improved assurance of cost recovery and an enhanced ability to keep rates low. Revenues under the FPS-07 rate schedule are credited against BPA's revenue requirement and, as such, FPS-07 will serve as one component of BPA's overall rate structure to ensure that, in the aggregate, BPA recovers its overall costs.

Section 3. Policy/Objectives of Firm Power Marketing for the FPS-07 Rate Schedule

Q. What role is the FPS-07 rate schedule intended to play towards BPA's overall revenue recovery in its WP-07 Initial Proposal?

A. The FPS-07 rate schedule plays a critical role in BPA's WP-07 Initial Proposal. To keep overall rates low for BPA's preference customers, the WP-07 forecast for revenues relies heavily on revenues generated by the sale of secondary energy. *See*, *e.g.,* WP-07-E-BPA-05, Ch. 5 (Revenue Forecast). Because of this reliance on secondary revenues, it is essential that BPA have a rate schedule that is flexible enough to allow it to sell power in the West Coast wholesale markets at prevailing market rates. Without such a mechanism, BPA's ability to meet its policy objective of providing low-cost power to its preference customers could be easily frustrated.

Q. How will BPA conduct business under the FPS-07 rate schedule?

A. BPA has sold, and will continue to sell, secondary energy in the real-time, day-ahead, balance-of-month and forward electricity markets. BPA engages in sales (and purchase) transactions with most of the major participants in the West Coast wholesale energy market. Like other market participants, BPA, in all of the aforementioned transactions, adheres to Western Systems Power Pool (WSPP) contract terms and conditions, which reflect industry standards. The proposed FPS-07 rate will be used in all of the transactions just described. As discussed in Section 5, it is also the rate schedule that will enable sales of non-requirement and non-standard products (e.g., surplus power, wind integration services, capacity, non-requirements sales to requirements customers, etc.) in markets throughout the west.

Section 4. Changes in BPA's Position in the West Coast Wholesale Power Market Since 1996

Q. How has the West Coast wholesale power market changed since 1996?

A. BPA continues to be an active participant in the West Coast wholesale energy market. However, since 1996, a number of factors have affected BPA's participation in that market. First, there has been a steady reduction in the amount of BPA's surplus firm power. This decrease in surplus firm power is primarily a function of increased regional load obligations over the past 10 years, and the return to BPA of a number of customers who left federal service during the 1990s.

In addition, there have been a large number of new entrants into the West Coast wholesale market, including independent power producers, power marketers, hedge funds and banks. The entry of these new participants has changed the competitive dynamics of the market, increasing market volatility, complexity, and liquidity.

Q. *How has the introduction of the Slice product changed BPA's participation in the West Coast wholesale market?*

A. The introduction of the Slice product has further reduced the amount of secondary energy BPA has available for sale in the West Coast wholesale market. The Slice product is a power sale, based upon a Slice customer's annual net firm requirements and is shaped to BPA's generation from a set of Federal system resources. The Slice product includes both service to net requirements firm load as well as an advance sale of surplus power. Under Slice, 22.6 percent of the output of the FCRPS is sold to 12 BPA customers who are responsible for marketing their share of the in the West Coast wholesale market. As a consequence, the surplus power available for BPA to market is proportionately reduced by the total percentage of the Slice product sold.

Q. Please explain the differences in available surplus that BPA foresees during the FY 2007-2009 rate period, as compared to the FY 2002-2006 rate period?

A. During the FY 2002-2006 rate period, BPA's contracted loads greatly exceeded the generation of the FCRPS. To meet this anticipated increase in load BPA made significant market purchases, known as augmentation. However, when some of the load failed to materialize, a firm surplus resulted. BPA resold this surplus in the West Coast wholesale market. In the coming rate period, BPA does not expect to have this surplus.

Except for a limited amount of surplus augmentation during the first three months of FY 2007, BPA does not anticipate having any significant amount of augmentation available for resale during the upcoming rate period. In FY 2007, BPA forecasts a firm surplus of only 15 aMWs and, beyond that, forecasts a limited augmentation need in FY 2008 and 2009 (to offset deficits of 38aMWs and 92aMWs, respectively). *See,* Load Resource Study, WP-07-E-BPA-01. Therefore, even if the forecasted load fails to materialize, any unneeded augmentation purchases will not significantly increase BPA's sales in the West Coast wholesale power markets.

Q. How have the changes in the West Coast wholesale energy market affected BPA's proposed design for the FPS-07 rate schedule?

A. The changes in the West Coast wholesale energy market, discussed above, have eliminated the rationale behind the need for the cost-based cap that applied to FPS-96 and FPS-96R. Therefore, BPA has not proposed any such cap on the FPS-07 rate schedule. More importantly though, as described above, BPA's footprint in the West Coast wholesale market has decreased while the number of participants in the market, overall market volatility, and market complexity have increased. It is critical that BPA be able to compete on a level playing field with the other players in the marketplace. Any sort of cost-based cap on the implementation of the proposed FPS-07 rate would unduly constrain BPA, putting it at an extreme disadvantage when competing against a number of sophisticated participants in an increasingly volatile and complex West Coast wholesale market. This type of disadvantage would greatly inhibit BPA's ability to meet its policy objective of providing low-cost power to its preference customers.

Q. Has BPA expanded its internal risk management policies on the marketing of its secondary energy since the start of the current rate period in a way that has affected the Agency's decision on the FPS-07 rate design?

A. Yes. Since FY 2002, BPA's internal policies for risk management have evolved alongside industry standards. BPA has established a large number of internal procedures that govern its marketing activities in the West Coast wholesale power market. In particular, BPA has created an Office of the Chief Risk Officer (CRO) with associated staff. Additionally, a Transacting and Credit Risk Management Committee (TRMC), composed of the CRO and other senior managers is chartered to establish limits for the Agency's commodity transactions and marketing activity. This committee also monitors these activities to ensure they stay within the established limits. To implement the directives of the CRO and TRMC, BPA has adopted a risk policy document. The risk policy document ensures that transacting activities are monitored and controlled through quantitative and qualitative limits so that BPA does not place itself, or other West Coast wholesale market participants, at undue risk from BPA's trading activities. These internal controls are an additional reason why it is unnecessary to have cost-based constraints on implementation of the proposed FPS-07 rate schedule.

Q. Have there been changes to tariffs and FERC policies that have impacted BPA's participation in the West Coast market?

A. Yes. The California Independent System Operator (CAISO) has instituted a tariff change that significantly impacted BPA's participation in that market. Amendment 66 to the CAISO tariff limits payments to importers (BPA, Powerex, PacifiCorp and other sellers into the CAISO market are considered importers) are paid their bid price as opposed to the market clearing price. Given, the cost based limitations BPA faces with the current FPS rate schedule, when market prices are above the current cost based cap, BPA is effectively denied participation in the CAISO markets.

Second, since 2002, FERC has established new policies that govern market activities. As a byproduct of the investigations and proceedings associated with the California energy crisis of 2000-2001, FERC instituted a West-wide price cap. When BPA first adopted the FPS-96 rate schedule, there was no FERC-mandated West-wide price cap. Today, this cap prohibits market participants from charging excessive prices for energy.

Q. *Does BPA intend to abide by the FERC West-wide price cap when making sales under the proposed FPS-07 rate?*

A. As part of its rate design for the FPS-07 rate, BPA proposes to adhere to a regime of price caps that is equivalent to the FERC west-wide cap. BPA's proposed price cap would rise or fall to match the FERC cap. It will neither advantage nor disadvantage BPA relative to any other market participant. The intent of this voluntary cap is to demonstrate BPA's commitment to participating in the market on a level playing field with other market participants.

Q. *What must FERC-jurisdictional utilities do to receive FERC permission to sell power at market based rates?*

A. Utilities over which FERC has jurisdiction must pass two new screens in order for the Commission to grant them the authority to sell at market-based rates. These new tests, known as the Pivotal Supplier screen and the Market Share screen, assess whether a market participant possesses generation market power that would enable it to influence prices.

As FERC pointed out in its Order granting final approval of BPA's SN-03 rate proceeding, FERC does not have jurisdiction over BPA's rate design. *See,* U.S. Dep't of Energy—Bonneville Power Admin., 107 FERC ¶ 61,138 at P 25 (2004). Accordingly, BPA need not apply to FERC for market-based rate authorization, or demonstrate passage of the two screens, in order to be able to promulgate a market-based rate such as the proposed FPS-07 rate.

Nevertheless, BPA recognizes that market power is an important issue for FERC and for market participants across the West. Therefore, BPA recently contracted with LECG, LLC, an independent consulting firm, to assess whether BPA would pass FERC's two generation market power screens. As described in further detail in the WPRDS, WP-07-E-BPA-05, Appendix C, and generally in Section 7 below, LECG concluded that

BPA passed the FERC screens within the overall Pacific Northwest market, as well as within BPA's own control area. These findings indicate that BPA does not have market power, and provide further support for BPA's assessment that it is appropriate for BPA to sell surplus firm power at a market-based rate.

Section 5. Rate Design

Q. Please describe the FPS-07 rate schedule.

A. As noted above, this rate schedule is intended to supersede FPS-96R. The FPS-07 rate schedule will be available for sales inside and outside the Pacific Northwest during the period beginning October 1, 2006, and ending September 30, 2009. This rate schedule will be available for the purchase of Firm Power, Capacity Without Energy, Supplemental Control Area Services, Shaping Services, and Reservation and Rights to Change Services. The FPS-07 rate schedule is designed to be flexible enough so that if a customer wants a product that is not specifically named in the rate schedule or defined in the GRSPs, but the product fits under a category listed in the rate schedule, BPA may sell the product under the FPS-07 rate. BPA may also combine separate products under one or more categories of the FPS-07 rate, and may combine FPS products with products from other rate schedules.

Firm Power is electric power (capacity and energy) that BPA will make continuously available under contract executed pursuant to Section 5 of the Northwest Power Act. Capacity Without Energy is the stand-ready obligation whereby BPA will deliver a contract-specific amount of power upon contract-specific notice provisions. Supplemental Control Area Services may be used to support control areas of utilities other than BPA and their control area service obligations. Shaping services are services provided by BPA to a Purchaser to shape the output of the Purchaser's resource (or purchase) to the Purchaser's load. Reservation and Rights to Change Services include the ability to reserve the right to change future deliveries of firm power, firm energy, capacity, unbundled power products, shaping services, and/or features of these deliveries.

Details about the products and services available under this rate schedule are described in the definition section of BPA's General Rate Schedule Provision (GRSPs). *See,* Initial Proposal for WP-07 Rate Case, 2007 Wholesale Power Rate Schedules and General Rate Schedule Provisions, WP-07-E-BPA-07, at 110-123.

Q. Please compare BPA's FPS-07 rate schedule with the FPS-96R rate schedule.

A. The FPS-07 rate schedule is very similar to the FPS-96R rate schedule with regard to the products it covers. BPA is not proposing any changes to the products offered in the FPS-07 rate schedule. For each of these products there is a Contract rate, and a Flexible rate. The Contract rate has a posted demand charge and posted heavy-load-hour and light-load-hour energy charges by month. The Contract rate includes a capacity-without-energy product. All of these rates have been updated for the FY 2007-2009 rate period based on BPA's Market Price Forecast Study, WP-07-E-BPA-03, and the operating reserve per-unit cost for capacity, WPRDS, WP-07-E-BPA-05, Section 4.1.3. Each charge has been expanded from either a single or seasonal charge to an individual monthly charge to be consistent with BPA's other power rate schedules.

Another similarity between the FPS-07 rate schedule and the FPS-96R rate schedule is that FPS-07 will include the Unauthorized Increase Charge (UAI) rate adjustment feature. The UAI is being updated and is the same as the UAI being applied to all other rate schedules. *See,* WP-07-E-BPA-07, at GRSPs Section II.Q.

Section 6. Term

Q. Why has BPA proposed a 3-year term for the FPS-07 rate schedule?

A. There are two reasons. First, a 3-year term matches BPA's rate period of FY 2007 through FY 2009. Administration of BPA's power rate schedules, particularly the GRSPs, is easier if they begin and end concurrently. Second, the three-year term also matches the length of the term of market-based rate authority that FERC grants to its jurisdictional utilities. After three years, FERC requires jurisdictional utilities to file an updated market power analysis. *See, Order on Rehearing and Modifying Interim Generation Market Power Analysis and Mitigation Policy*, 107 FERC ¶ 61,018 at 6 n3 (April 14, 2004). For consistency with FERC-jurisdictional market participants, BPA has opted to voluntarily adhere to the same time limitation.

Section 7. Market Power Study (Witness Phillip W. McLeod)

Q. Please name your employer and summarize the nature of your employer's business.

A. My employer is LECG, LLC. LECG is a global expert services firm; it provides independent expert testimony, original authoritative studies, and strategic advisory services to clients including Fortune Global 500 corporations, major law firms, and local, state, and federal governments and agencies around the world. LECG's highly credentialed experts and professional staff, conduct economic and financial analyses to provide objective opinions and advice that help resolve complex disputes and inform legislative, judicial, regulatory, and business decision makers. LECG's experts are renowned academics, former senior government officials, experienced industry leaders, and seasoned consultants.

Q. What did BPA hire you and/or LECG to do?

A. BPA hired me to assess whether BPA's Power Business Line is able to exert horizontal market power in its regional markets based on two new market power screens adopted by FERC in 2004. BPA is not under FERC's jurisdiction over market-based rate authorization; however, electric utilities under FERC's jurisdiction must submit analysis using these screens in all initial market-based rate applications and in triennial reviews on an interim basis.

Q. What was your role in completing the Generation Market Power Study for BPA?

A. I provided overall direction for the analysis and prepared the report on the study submitted to BPA. I also directed the development of the methodology for the analysis, and supervised the collection of necessary data and performance of the necessary calculations for the analysis.

Q. *As the principal consultant performing the Generation Market Power Study, please describe the methodology (i.e. tests/screens) you employed.*

A. The two FERC market power screens are the Pivotal Supplier screen and the Market Share screen. The Pivotal Supplier screen addresses whether the applicant can exercise market power unilaterally based on the ability of other suppliers to meet market demand. An applicant passes the Pivotal Supplier screen if wholesale sales during the peak month can be met without the applicant's uncommitted supplies. The Market Share screen addresses whether the applicant has a dominant position in the market based on its share of uncommitted supplies in the market during each of the four seasons. An applicant passes the Market Share screen if its share of uncommitted capacity is less than 20 percent.

The analyses used historical data for the 2003 calendar year (this was the most recent year for which complete data was available) and examined two relevant regional markets. The first is the BPA Transmission Business Line's (TBL's) control area and its first-tier markets (i.e., markets that are directly connected to the applicant's market area) consisting of 16 connected control areas. The second market is the larger Pacific Northwest (PNW) region and its first-tier markets consisting of three connected control areas.

The Pivotal Supplier analysis is based on first calculating the uncommitted supplies of both the applicant and other suppliers available to compete for the wholesale load in the relevant market. This is a measure of supplies in the market not committed to meet firm long-term obligations such as utilities' native loads and long-term sales. Uncommitted supply is the difference between net supplies available and load obligations. Net supplies available equal the total nameplate capacity of generation owned or controlled through contracts and firm purchases, less operating reserves and other capacity adjustments. Load obligations are the sum of native load commitments and long-term firm sales. The capacity available for wholesale sales is calculated by adding the total uncommitted capacity of the applicant and other suppliers within the market area to the capacity of potential imports from first tier markets. The net uncommitted supply is then calculated as the capacity available for wholesale sales less the wholesale load. The wholesale load is estimated as the annual system peak load less the proxy for the native load obligation (i.e., the average of the daily native load peaks, excluding weekend days and holidays, during the month in which the annual peak load occurs). If the applicant's uncommitted capacity is less than the net uncommitted market supply, then the applicant passes the Pivotal Supplier screen.

The Market Share analysis also requires the calculation of the applicant and other suppliers' uncommitted capacity with some variations. The calculation is done for each of the four seasons, and the proxy native load is defined as the minimum peak day load for each season considered. Suppliers are also adjusted for any seasonal variations such as planned outages and long-term contract commitments. The applicant's market share is then calculated based on its uncommitted capacity as a percent of the total uncommitted capacity available to serve the wholesale market. If the applicant's market share is less than 20 percent in each of the four seasons, then it passes the Market Share screen.

Q. Please summarize the findings of the Generation Market Power Study you and LECG completed for BPA.

A. For the Pivotal Supplier screen, our analysis indicates that BPA's dependable supplies were fairly well balanced with its firm long-term sales obligations during peak periods in 2003. In fact, under the definition of generating capacity used in FERC's Pivotal Supplier screen, BPA would be short 730 MW if it had to meet its total contract capacity obligations during the peak period of the year. Other suppliers both within the BPA control area and in the larger PNW have significant amounts of uncommitted supplies, which allow them to satisfy the market's wholesale loads without reliance on BPA supplies. As a result, BPA passes the Pivotal Supplier screen in both regional market areas very easily.

In terms of the Market Share screen analysis, BPA's supply/demand balance leaves it with very limited uncommitted capacity relative to other suppliers during each of the four seasons of the year. In the BPA control area market, BPA's market share of potential uncommitted supplies is, at the most, 9 percent in the spring season, 7 percent during the winter and summer seasons, and 1 percent in the fall season. In the PNW market, BPA's market share is 7 percent in the winter and summer seasons, 6 percent in the spring season and less than 1 percent in the fall season.

Q. Are there particular factors that were especially significant to your finding that, under the relevant FERC screens, BPA does not possess market power?

A. There are three such factors. The first factor that is significant to BPA passing the market screens is the extensive transmission systems connected to both the BPA control area and the PNW. These systems allow large amounts of imports to enter both the BPA control area and the PNW. A second factor of importance is BPA's large contractual obligations to supply energy and capacity to a large number of public utilities within the BPA control area and the PNW. As a result of these obligations, BPA has very little surplus firm capacity with which to control the wholesale market. The third factor of importance is BPA's heavy reliance on hydroelectric generation. The seasonal nature of this generation, along with its annual variation, requires that the nameplate capacity of these hydro facilities be derated significantly (consistent with provisions in the FERC market power screens) when computing the firm supplies BPA has available to influence the market.

Q. Is a final copy of the Generation Market Power Study included in this initial proposal?

A. Yes, it is contained in WPRDS, WP-07-E-BPA-05, Appendix C.

Section 8. NF-02 Rate

Q. Has BPA decided to propose elimination of the NF-02 rate schedule?

A. Yes. The NF-02 rate schedule has traditionally been available for the sale of nonfirm energy both inside and outside the Pacific Northwest. BPA no longer uses the NF rate schedule primarily because changes in the West Coast energy markets have rendered it obsolete. The West Coast power markets have evolved in recent years in a way that only firm power products are generally available. BPA has not made any sales under this rate schedule during the current rate period (FY 2002-2006) and, given the lack of any active nonfirm market in the west, BPA does not foresee any sales in the coming rate period. Thus, BPA proposes to eliminate the NF rate schedule in the upcoming rate period.

Q. Does this conclude your testimony?

A. Yes.

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TESTIMONY OF

BYRON G. KEEP, WILLIAM J. DOUBLEDAY, PAUL A. BRODIE,

AND MICHAEL MACE

Witnesses for Bonneville Power Administration

SUBJECT: SECTION 7(b)(2) RATE TEST STUDY

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TESTIMONY OF

BYRON G. KEEP, WILLIAM J. DOUBLEDAY, PAUL A. BRODIE,

AND MICHAEL MACE

Witnesses for Bonneville Power Administration

SUBJECT: SECTION 7(b)(2) RATE TEST STUDY

Section 1. Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Byron G. Keep. My qualifications are stated in WP-07-Q-BPA-22.

A. My name is William J. Doubleday. My qualifications are stated in WP-07-Q-BPA-11.

A. My name is Paul A. Brodie. My qualifications are stated in WP-07-Q-BPA-07.

A. My name is Michael Mace. My qualifications are stated in WP-07-Q-BPA-33.

Q. Please state the purpose of your testimony.

A. The purpose of this testimony is to sponsor Bonneville Power Administration's (BPA) Section 7(b)(2) Rate Test Study, WP-07-E-BPA-06, and Documentation, WP-07-E-BPA-06A.

Q. Please summarize your testimony and its organization.

A. This testimony will discuss the implementation of the rate test established by section 7(b)(2) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act). Section 1 outlines the purpose of this testimony. Section 2 discusses the Section 7(b)(2) Implementation Methodology. Section 3 discusses the determination of the test period for the 7(b)(2) rate test. Section 4 discusses the changes in the model used to run the rate test. Section 5 discusses the financing benefits analysis performed by BPA’s financial advisor, Public Financial Management (PFM), and the application of that analysis to the rate test. This is the only section on which Mr. Mace is offering testifying. Section 6 discusses resource acquisitions in the 7(b)(2) Case. Section 7 discusses the identification of non-dedicated resources in the 7(b)(2) Case. Section 8 discusses the treatment of conservation in the rate test. Section 9 notes that there are no reserve benefits resulting from the ability to restrict direct service industrial customer (DSI) loads because BPA is forecasting no sales to such loads for the WP-07 rate period. Finally, Section 10 summarizes the results of the rate test.

Section 2. The 7(b)(2) Rate Test

Q. What is the 7(b)(2) rate test?

A. Section 7(b)(2) of the Northwest Power Act requires that BPA perform a rate test in each rate proceeding or "when setting rates" after July 1, 1985. The rate test ensures that BPA's preference customers' firm power rates applied to their general requirements are no higher than rates calculated using five specific assumptions that remove certain effects of the Northwest Power Act. *See,* Section 7(b)(2) Implementation Methodology Record of Decision (Implementation Methodology) (B-2-84-F-02).

Q. How was the 7(b)(2) rate test performed for BPA's WP-07 initial proposal?

A. The rate test involves the projection and comparison of two sets of wholesale power rates for the general requirements loads of BPA's public body, cooperative, and Federal agency customers (7(b)(2) or preference customers). The two sets of rates are: (1) a set for the rate filing period (FY 2007-2009) and the ensuing 4 years (FY 2010-2013) assuming that section 7(b)(2) is not in effect (Program Case rates); and (2) a set for the same period taking into account the five assumptions listed in section 7(b)(2) (7(b)(2) Case rates). The 7(b)(2) Case rates are modeled the same as the Program Case rates except for the five assumptions listed in section 7(b)(2). The five assumptions used to model the 7(b)(2) Case are:

1. DSI loads within or adjacent to public service areas are transferred to public utilities at the start of the 7(b)(2) rate test period; the remaining DSI loads are transferred to investor-owned utilities (IOUs) as BPA/DSI pre-Northwest Power Act contracts expire.

2. 7(b)(2) customers are served with Federal Base System (FBS) resources not obligated to non-

preference loads under contracts existing as of the effective date of the Northwest Power Act.

3. No section 5(c) Residential Exchange Program (REP) takes place.

4. Additional resources of three specified types serve the loads of 7(b)(2) customers when FBS resources are exhausted. These resources are outlined in the 7(b)(2) resource stack.

5. The DSI reserve benefits under provisions of the Northwest Power Act are not available in the 7(b)(2) Case. Financing benefits under provisions of the Northwest Power Act are not available in the 7(b)(2) Case. The 7(b)(2) Case rates will reflect these increased costs to the 7(b)(2) customers.

For a discussion of the development of the Program and 7(b)(2) Case rates, *see,* Section 7(b)(2) Rate Test Study, WP-07-E-BPA-06, and Documentation, WP-07-E-BPA-06A.

Q. What was done after the two sets of rates were developed?

A. Certain specified costs allocated pursuant to section 7(g) of the Northwest Power Act were subtracted from the Program Case rates. Next, the nominal rate for each year was discounted to the beginning of the test year of the relevant rate case, in this case FY 2007. The discounted Program Case rates were averaged, as were the 7(b)(2) Case rates. Both averages were rounded to the nearest tenth of a mill for comparison. Because the average Program Case rate was higher than the average 7(b)(2) Case rate, the rate test triggered.

Q. Was the 7(b)(2) rate test conducted in generally the same manner for the WP-07 Initial Proposal as it was in past rate filings?

A. Yes. However, BPA used an updated computer model to conduct the test for the WP-07 Initial Proposal. This model is discussed in greater detail in Section 4.

Q. Will changes be made to the 7(b)(2) resource stack in calculating rates for the final rate proposal?

A. Yes. After BPA had finished calculating rates for the WP-07 Initial Proposal it was discovered that the costs for conservation resources contained in the resource stack were incorrect. The costs for conservation resources contained in the resource stack that were used in the initial rate proposal along with the correct costs for conservation resources are included in the Section 7(b)(2) Rate Test Study Documentation, WP-07-E-BPA-06A, Appendix B. The differences in the costs for conservation resources would have slightly changed the results of the section 7(b)(2) rate test but would not have changed the actual initial proposal's rates. In addition to correcting the costs of conservation resources, it is anticipated that the resource costs and energy amounts relating to other resources in the resource stack will also be updated in calculating rates for the final rate proposal.

Section 3. Test Period

Q. Please describe the determination of the test period for the 7(b)(2) rate test.

A. In BPA's WP-07 Initial Proposal, BPA assumed a three-year rate period. The 7(b)(2) Implementation Methodology states that the test period will consist of the test year for the relevant rate case plus the ensuing four years. In developing the rates in BPA's initial proposal, BPA used all three years as the test period, i.e., a 36-month test period. Therefore, because the test period is three years, BPA used those three years (FY 2007-2009) plus the ensuing four years (FY 2010-2013) as the 7(b)(2) rate test period.

Section 4. Changes in the Rate Analysis Model

Q. What type of computer model is required to conduct the 7(b)(2) rate test?

A. In order to calculate the annual PF rates for the Program and 7(b)(2) Cases, a model that simulates BPA's rate-making processes should be used. The Program Case modeling produces a forecasted projection of annual rates that reflect BPA's actual forecasted data and policies for the rate period, while the 7(b)(2) Case modeling allows the incorporation of the 7(b)(2) assumptions.

Q. What computer models has BPA previously used to conduct the 7(b)(2) rate test?

A. In BPA's WP-85 rate case, where BPA first conducted the 7(b)(2) rate test, BPA used the FORTRAN-based Supply Pricing Model (SPM). BPA also used the SPM in subsequent wholesale power rate cases, including the WP-96 rate case. In BPA's WP-02 rate case, BPA used the 2002 Rate Analysis Model (RAM2002), which consists of five large Excel spreadsheets that work together by the use of Visual Basic macros. BPA now uses the 2007 Rate Analysis Model (RAM2007), a single automated Excel spreadsheet, to conduct the test.

Q. Why did BPA develop RAM2007 to conduct the 7(b)(2) rate test and to prepare rates for the WP-07 rate period?

A. The need for greater efficiency and flexibility in rate analysis prompted BPA to develop RAM2007. Although RAM2002 was developed specifically for the five-year WP-02 rate period and the associated nine-year 7(b)(2) test period, RAM2007 was developed to provide the capability to forecast rates over a ten-year period. In addition, whereas RAM2002 was designed to accurately model the WP-02 rate case assumptions, RAM2007 will accommodate different scenarios and will forecast 7(b)(2) rate test triggers and rates for the 2007-2009, 2010-2011, and 2012-2013 rate periods (assuming BPA moves to two-year power rate periods in the future).

Q. Please briefly describe RAM2007.

A. RAM2007 is a large Excel spreadsheet model that is automated with Visual Basic macros. RAM2007 is intended to be more operator-friendly than RAM2002.

Q. Please describe how RAM2007 is more operator-friendly.

A. RAM2007 is operated from a pull-down menu and explicitly shows the rate results after each rate-making step. RAM2007 automatically determines which of the possible exchanging utilities will be exchanging as the unbifurcated PF and PF Exchange rates are developed. RAM2002 relied on inspection by the analyst to determine the number of utilities participating in the Residential Exchange Program (REP). RAM2007 calculates the PF Slice product cost for each year and incorporates those data in the calculation of the PF Preference rate. Because Slice contracts had not yet been signed at the time of the WP-02 rate case, RAM2002 did not use Slice product cost data in the calculation of rates.

Q. Is the RAM2007 model BPA used to conduct the 7(b)(2) rate test also used to develop BPA's WP-07 Initial Proposal?

A. Yes. The forecasts and policy assumptions used in the Program Case of the 7(b)(2) rate test are also used in the calculation of posted rates for the WP-07 Initial Proposal. RAM2007 conducts the 7(b)(2) rate test as just one of several rate-making steps to produce annual rates. Although the 7(b)(2) rate test is conducted using a forecast of seven annual PF rates for the test period, RAM2007 groups three years (36 months) of costs, credits, and sales together to calculate average rates for the three-year rate period.

Q. How does RAM2007 incorporate those portions of the Section 7(b)(2) Implementation Methodology that determine how the 7(b)(2) projections are made?

A. The 7(b)(2) sections of RAM2007 differ from the Program Case sections of RAM2007 by the five section 7(b)(2) assumptions:

1. *<u>The within or adjacent DSI loads are added to the PF sales forecast, and no IP load or rate class is assumed.</u>* For the rate period, no direct service to the DSIs has been forecast, therefore there is no addition to PF load due to DSI service in the RAM2007 7(b)(2) Case.

2. *<u>7(b)(2) customers are served with FBS resources not obligated to other non-preference loads under contracts existing as of the effective date of the Northwest Power Act.</u>* For the rate period, the FBS available to serve PF load is slightly larger in the 7(b)(2) Case than in the Program Case due to this provision.

3. *<u>No section 5(c) REP takes place, and no PF Exchange load or rate class is assumed.</u>* For the rate period, because IOU REP Settlement Agreement costs are associated with the REP, these costs are not included in the 7(b)(2) Case.

4. *<u>A section 7(b)(2) resource stack with resources sorted from least to most costly has been constructed to serve 7(b)(2) customers after the FBS is exhausted. In addition, PF sales forecasts are increased by forecasts of programmatic conservation, and annual conservation programs that are included in the 7(b)(2) resource stack.</u>* For the rate period, PF load in the

7(b)(2) Case has been increased by foregone conservation and the model goes to the 7(b)(2) resource stack to maintain load/resource balance through the test period.

5. <u>*Reserves provided by the DSIs are included as an increased cost to the 7(b)(2) customers. The cost of resources reflects that financing benefits under provisions of the Northwest Power Act are not available in the 7(b)(2) Case.*</u> For the rate period, no reserves are forecast to be provided by the DSIs and increased resource costs due to the lack of financing benefits are incorporated in the 7(b)(2) resource stack.

Q. How are the annual costs of additional resources calculated in the 7(b)(2) Case in RAM2007?

A. The capital costs, operations and maintenance costs, and fuel costs for each resource are included in the 7(b)(2) resource stack in 1980 dollars. The cumulative total cost of the needed resources is determined as the resources are brought on-line. The cumulative total in 1980 dollars is then escalated to the current year for each year of the test period.

Q. How is RAM2007 organized?

A. RAM2007 has three main steps: a Rate Design Step, a Subscription Step, and a Slice Separation Step.

Q. Is this stepped rate-making similar to that used in RAM2002?

A. Yes. RAM2002 developed rates in a two-step process. In 2002, Program Case rates for the 7(b)(2) Rate Test were calculated in the Rate Design Step using all costs including a forecast of gross exchange costs for the IOUs. BPA then conducted a Subscription Step to calculate rates assuming the IOUs had signed their Subscription REP Settlement Agreements.

Q. Please provide a brief description of how the RAM2007 Rate Design Step works.

A. The RAM2007 Rate Design Step follows BPA's rate directives by determining the costs associated with the three resource pools (FBS resources, Residential Exchange resources, and new resources) used to serve sales load and then allocating those costs to the rate pools (PF, IP, and NR). After the initial allocation of costs, the Northwest Power Act requires that some rate adjustments be made, such as those described in sections 7(b) and section 7(c) of the Act. RAM2007 performs these rate adjustments, including the 7(b)(2) rate test, in its Rate Design Step. The Rate Design Step of RAM2007 concludes with the calculation of the Rate Design Step rates. At this point in the modeling, all posted rates are still preliminary except for the PF Exchange rate, which is set and is then used to calculate the net cost of any public utility participation in the REP.

Q. Please provide a brief description of how the RAM2007 Subscription Step works.

A. RAM2007 includes a Subscription Step to calculate power rates, which includes the costs of the IOUs' Subscription REP Settlement Agreements. The Subscription Step takes the results of the Rate Design Step and adjusts them by first subtracting any net-cost of the traditional REP for the IOUs that has been included in the Rate Design Step rates, and then adding the costs of the IOU REP Settlement Agreements.

Q. Please provide a brief description of the Slice Separation Step.

A. In the Rate Design and Subscription steps, costs were allocated to the various rate pools, including the PF Preference rate pool that contained all firm PF Preference load. The Slice Separation Step separates out the PF Slice product revenues and firm loads from the overall PF Preference rate pool, leaving the costs that must be covered by the remaining non-Slice product PF Preference load through posted PF Preference energy, demand, and load variance charges.

Q. In the WP-07 Initial Proposal, with the IOUs' REP Settlement Agreements now signed, why is BPA continuing to forecast IOU ASCs and exchangeable load in the 7(b)(2) rate test?

A. The section 7(b)(2) rate test compares Program Case rates with 7(b)(2) Case rates. Section 7(b)(2) of the Northwest Power Act provides that the REP does not exist in the 7(b)(2) Case. Historically, BPA has always conducted the 7(b)(2) rate test with the REP reflected in the Program Case and the REP absent from the 7(b)(2) Case. BPA has continued this comparison in conducting the 7(b)(2) rate test by forecasting the IOUs' participation in the REP in the Program Case.

Also, the PF Exchange rate is used to determine exchanging utilities' benefits under the REP. Historically, the size of the REP has been a large factor in determining whether the 7(b)(2) rate test will trigger. Also, the costs to be reallocated due to the 7(b)(2) rate test trigger have been largely allocated to the PF Exchange rate. This relationship between the size of the REP and the magnitude of the costs represented by the 7(b)(2) trigger amount that are reflected in the PF Exchange rate is preserved by forecasting IOU participation in the REP in the Rate Design Step. In the Rate Design Step BPA conducts the 7(b)(2) rate test, which determines the PF Exchange rate.

Q. *How are IOU REP Settlement Agreement costs incorporated into BPA's final proposed rates?*

A. In the WP-02 rate case, the Subscription Step assumed that regional IOUs executed proposed settlements of the REP instead of electing to participate in the REP. BPA then allocated the costs of such settlements to rates in the Subscription Step. The IOU REP settlements have now occurred and BPA now knows the costs of the Amended Settlement Agreements that provide a floor and a cap to settlement benefits. BPA is continuing the methodology developed in the WP-02 rate case of allocating settlement costs in the Subscription Step. In the WP-07 rate case, however, BPA is allocating the actual FY 2007 and the forecast FY 2008-09 costs of these settlements instead of allocating assumed settlement costs.

Section 5. Financing Analysis

Q. What is the financing analysis?

A. Section 7(b)(2)(E) of the Northwest Power Act directs the Administrator to assume for purposes of the rate test that quantifiable monetary savings resulting from reduced public body and cooperative financing costs were not achieved. The financing analysis determines resource financing costs associated with different resource types identified in section 7(b)(2) of the Northwest Power Act for public agency and other resource sponsors with and without a BPA acquisition contract. The financing analysis was prepared under contract by Public Financial Management (PFM), BPA's current financial advisor, and is included in the Section 7(b)(2) Rate Test Study Documentation, WP-07-E-BPA-06A, Appendix A.

Q. Please describe the primary conclusion that can be drawn from the financial analysis.

A. The primary conclusion that can be drawn from the financial analysis is that for most types of financing there is a positive benefit from BPA providing financial backing to the resources financed in the Program Case when compared to the financing costs projected in the 7(b)(2) Case, where resource financings do not receive the benefit of BPA financial backing.

Q. Please summarize the financing analysis' specific conclusions regarding the financing of specific resource types using different debt maturities.

A. For generation or conservation resources financed with 25-year public Joint Operating Agency (JOA) revenue bonds, the financing analysis (Appendix A, Section 3, Table A) provides that resources financed with BPA backing in the Program Case would have received financing at a rate of 5.24%, compared to a higher rate of 5.42% for the 7(b)(2) Case without BPA financial backing. Thus, long-term resource investments financed over 25 years would receive an 18 basis point advantage in the Program Case over the 7(b)(2) Case. If generation or conservation resources were financed with 20-year public JOA revenue bonds backed by BPA in the Program Case, they would have received a more favorable financing rate of 5.17% compared to a higher rate of 5.34% for the 7(b)(2) Case without BPA financial backing. If generation or conservation resources were financed with 15-year public JOA revenue bonds backed by BPA in the Program Case, they would have received a more favorable financing rate of 4.93% compared to a higher rate of 5.09% for the 7(b)(2) Case without BPA financial backing. The resulting financial benefit from BPA's financial backing in the Program Case for 20 and 15-year financings would be 17 and 16 basis points, respectively, under these projected financings. The financial analysis also provides estimates of interest rate differentials with and without a BPA acquisition contract for named resources, such as Cowlitz Falls, and for resources acquired from non-7(b)(2) customers, such as resources from independent power producers. These conclusions are found in Appendix A, Section 3, Table A.

Q. Was the financing analysis conducted using the same methodology that was used in BPA's WP-02 rate case?

A. Yes, in large part. In performing the financing analysis, PFM generally used the same methodology that was used in the WP-02 rate case. As in past financing analyses, the projected interest rates for debt with BPA backing and JOA-issued debt without BPA backing are based on historic borrowing costs for different rating categories of bonds previously issued. However, the types of debt and the time periods examined are different. Past financing analyses relied primarily on the Bond Buyer 25-Bond Revenue Bond Index, which was not specific to electric power related financings. Past financing analyses also used a historic range of years dating from 1982 to 1998. The current financing analysis relies primarily on historic rate differentials for A and AA rated revenue bonds that are specific to the electric utility industry and based on the last ten years (FY 1996-2005). The financial data in the current study was obtained from the Bloomberg Capital Market yield curve indices. PFM has broad professional experience in matters concerning credit markets, the activities of BPA and other public and private utilities in the Pacific Northwest, and other utilities located throughout the country. PFM used its professional judgment in revising and developing assumptions surrounding the projection of interest rates for the different types of resources using the different debt maturities that were present in the resource stack.

Q. How were the results of the financing analysis applied in the 7(b)(2) rate test?

A. When additional resources were needed to meet 7(b)(2) customers' loads in the 7(b)(2) Case that are in excess of the capability of FBS resources, section 7(b)(2)(D) of the Act provides that three types of resources are used in the 7(b)(2) Case resource stack to meet these loads.

They are: Type 1, actual and planned resource acquisitions by BPA from 7(b)(2) customers consistent with the Program Case; Type 2, existing 7(b)(2) customer resources not currently dedicated to regional preference loads; and Type 3, generic resources at the average cost of actual and planned resource acquisitions by BPA from non-7(b)(2) customers consistent with the Program Case.

Type 1 resources within the resource stack are: Cowlitz Falls Hydro Project, Idaho Falls Hydro Project, Billing Credit Resources, and Conservation Resources. The interest rate differential of an additional 5 basis points identified in the financial analysis for the Cowlitz Falls Hydro resource is reflected in the debt service costs for this resource within the resource stack. The additional 18 basis points in financing costs for Billing Credit Resources in the 7(b)(2) Case identified in the financing analysis were factored into the costs contained in the resource stack for those resources. The financing analysis' projection for financing conservation resources for terms of 15 and 20-years using interest rates of 5.09% and 5.34% for the 7(b)(2) Case were factored into the resource costs for conservation resources within the resource stack.

Type 2 resources contained in the resource stack that were used to meet the loads in the 7(b)(2) Case are portions of the Mid-Columbia dams (Wells, Rocky Reach, Rock Island, Wanapam, and Priest Rapids) owned by 7(b)(2) customers (Douglas PUD, Chelan PUD, and Grant PUD) that were not projected to be serving preference customer loads during the 7 (b)(2) Case rate test period. Type 2 resources do not require a financial analysis because they are already financed and constructed (*see* Section 7(b)(2) Implementation Methodology, Section III, Financing Benefits, page 12, footnote 8).

Examples of Type 3 resources contained in the resource stack include recent wind project resource purchases. The financing analysis' favorable financing benefits of 137 basis points compared to the Program Case (the interest rates used in the 7(b)(2) Case were less expensive by 1.37 percent) were reflected in the cost of acquiring these resources in the7(b)(2) Case.

Section 6. Resource Acquisitions

Q. Were 7(b)(2) customer loads the same in the Program and 7(b)(2) Cases?

A. No. As provided in the Implementation Methodology, 7(b)(2) Case customer loads were increased by the amount of actual or planned conservation included in developing the Program Case loads.

Q. Were resources needed in addition to FBS resources to serve the 7(b)(2) customers' loads in the 7(b)(2) Case?

A. Yes. Additional resources were needed to serve the 7(b)(2) customer loads from the start of the test period.

Q. How was the amount of additional resources needed to serve the 7(b)(2) customers' loads in the 7(b)(2) Case calculated?

A. The RAM2007 model conducts a load/resource balance calculation in the 7(b)(2) Case for each year of the test period.

Q. How was the 7(b)(2) Case PF load forecast determined?

A. The PF load forecast for the 7(b)(2) Case begins with the PF loads from the Program Case and adds load associated with foregone conservation savings. Over the test period, the increase in 7(b)(2) PF load over and above the Program Case PF load due to foregone conservation is approximately 796 aMW. No direct sales to Direct Service Industrial (DSIs) customers are forecast for the rate period; therefore, no additional PF load was assumed for within or adjacent DSIs in the 7(b)(2) Case.

Q. How were resources added to serve the 7(b)(2) Case load?

A. As established in the Implementation Methodology, and as described above, three types of additional resources may be added to serve 7(b)(2) customer loads. They are: Type 1, actual and planned resource acquisitions by BPA from 7(b)(2) customers consistent with the

Program Case; Type 2, existing 7(b)(2) customer resources not currently dedicated to regional preference loads; and Type 3, generic resources at the average cost of actual and planned resource acquisitions by BPA from non-7(b)(2) customers consistent with the Program Case.

A cost was calculated for each of the first two types of resources. Type 1 and Type 2 resources were stacked together in least-cost-first order in discrete increments reflecting the actual size of the resource or the increment actually acquired by BPA. These resources were assumed to come on-line in the order in which they were stacked to meet the general requirements of the 7(b)(2) customers when FBS resources are exhausted. When conservation or a billing credit resource was the least-cost resource selected, the amount (megawatts) of conservation or billing credit was treated as a reduction to the 7(b)(2) Case loads consistent with its treatment in the Program Case.

Q. Were any Type 3 resources required to meet 7(b)(2) Case loads in performing the rate test?

A. No.

Section 7. Non-Dedicated Mid-Columbia Resources

Q. Has BPA identified any Type 2 resources (existing 7(b)(2) customer resources not currently dedicated to their regional loads)?

A. Yes. Section 7(b)(2)(D)(ii) of the Northwest Power Act provides that, in addition to FBS resources, 7(b)(2) customers' loads in the 7(b)(2) Case are met with such customers' "resources not committed to load pursuant to section 5(b)." BPA's Legal Interpretation of Section 7(b)(2) at page 16 also refers to "resources owned or purchased by the 7(b)(2) customers, and not dedicated to their own loads." In reviewing these resources for BPA's 1996 rate case, BPA identified resource capability associated with the Mid-Columbia dams (Wells, Rocky Reach, Rock Island, Wanapam, and Priest Rapids) owned by 7(b)(2) customers (Douglas PUD, Chelan PUD, and Grant PUD) that were not used to meet regional preference customer loads. In addition to the Mid-Columbia dams, the current resource stack also contains other resources owned or purchased by preference customers that are not dedicated to regional preference loads.

While our WP-07 Initial Proposal on this issue is consistent with past rate case positions on this issue, this will be the first time that, as a practical matter, our approach to the issue has significantly influenced the section 7(b)(2) Rate Test to increase the PF Exchange rate. Consequently, we anticipate a much more focused and thorough examination of this issue by rate case parties than in the past, all of which will serve to inform the Administrator's final decision.

Q. Prior to BPA's WP-96 rate case, were the Mid-Columbia dam resources included in the 7(b)(2) resource stack?

A. Yes. A small amount of power had been included in the 7(b)(2) resource stack prior to the WP-96 rate case. This was power from the Mid-Columbia dams that was assumed to be non-dedicated because it was sold outside the region.

Q. Why did the amount of resource capability associated with the Mid-Columbia dams included in the 7(b)(2) resource stack change in BPA's WP-96 rate case?

A. Prior to the WP-96 rate case, BPA had mistakenly assumed that the distinction between a sale to an end-user that was inside or outside the region was relevant to the inclusion of a resource in the 7(b)(2) resource stack. In both the WP-96 and WP-02 rate cases, however, BPA included power from the Mid-Columbia dams that was sold to regional investor-owned utilities as non-dedicated resources for 7(b)(2) rate test purposes. This power was produced by resources owned by 7(b)(2) customers and the power was not dedicated to regional preference customer loads. The resource amounts and costs are documented in the 7(b)(2) resource stack. *See* Section 7(b)(2) Rate Test Study Documentation, WP-02-E-BPA-06A, Appendix C.

Q. *Did the quantity of Mid-Columbia resources contained in the WP-07 resource stack change from the WP-02 resource stack?*

A. Yes. In the WP-02 rate case the quantity of Mid-Columbia resources was 1,697 aMW of energy. In the WP-07 rate case the quantity of Mid-Columbia resources is 845.6 aMW of energy, a decrease of 50.2 percent. The reduction is due to the expiration of several purchase power contracts and the reallocation of this energy in new purchase power agreements. In the new agreements a greater portion of the output from the projects serves regional preference loads, decreasing the amount available to the WP-07 7(b)(2) Case resource stack. The documentation supporting the projections of energy allocated to preference and non-preference purchasers is provided in Appendix C of the Section 7(b)(2) Rate Test Study Documentation, WP-07-E-BPA-06A.

Q. Has BPA changed the way it determines the cost of the Mid-Columbia resources?

A. Yes. In the WP-02 rate case, data was taken from the Power Dat Data Base. The Mid-Columbia resource costs were determined on a total resource basis. The projects were priced on the basis of the total capital and annual operations and maintenance costs for each resource. Individual utility overhead costs were not used in determining the costs of these resources in the WP-02 rate case.

For the WP-07 rate case, BPA requested the financial and operating costs associated with the Mid-Columbia projects from the project owners. The project owners provided projected operating budget and financial data for a single fiscal year (FY 2005 or FY 2006) for all but one of the dams (Wanapum). Most project owners also provided individual utility energy allocation projections for their projects for OY 2006 (July 1, 2005 - June 30, 2006). The budget cost projections for operating these generating resources were combined with the audited financial information and supplemental information contained in the annual reports pertaining to the generation segments for FY 2002-2004. The cost trends present in the audited financial information together with the project owners' operating budget submissions were combined to produce a financial projection of the operating cost for each project for FY 2007. The portion of the projected 2007 cost of operation budgets (based on historical costs) that was attributable to the non-preference allocations of energy was included in the WP-07 7(b)(2) Case resource stack. *See* Section 7(b)(2) Rate Test Study Documentation, WP-07-E-BPA-06A, Appendix C.

Q. *What is the difference in the weighted average cost of Mid-Columbia resources contained in the WP-02 resource stack versus the cost used in the WP-07 resource stack?*

A. The cost of the Mid-Columbia resources increased by 22 percent in the WP-07 resource stack when compared to the costs in the WP-02 resource stack. Primary drivers for the increased cost of operations for these projects were generator replacements, power house improvements, fish and habitat improvement costs, and relicensing costs. The weighted average projected WP-07 operating cost for the five Mid-Columbia resources is $17.52/MWh.

Q. *Please describe how the Mid-Columbia resources are modeled in the 7(b)(2)Case.*

A. For the 7(b)(2) Case, the combined annual operating costs and financing costs (projected operating budget amount) were treated as a single expense that was added to the 7(b)(2) Case revenue requirement in the year the resource was chosen from the resource stack. Subsequent years' costs were increased for inflation based on forecasted inflation estimates obtained from the financial forecasting firm of Global Insight.

Section 8. Conservation

Q. *Please describe how conservation savings and related costs were formulated in conducting the 7(b)(2) rate test.*

A. The conservation savings and the related costs contained in BPA's **"**Conservation Resource Energy Data – The Red Book**"** (Red Book)**,** published in February 2005, provided the basis for BPA's historical conservation savings (investments) for FYs 1982-2004 contained in the 7(b)(2) Case resource stack. The projected conservation savings and related costs associated with BPA's conservation program budgets as contained in the Program Case revenue requirement provided the basis for conservation investments for FYs 2005-2013.

Q. *Please explain adjustments that were made to the Red Book's conservation savings and costs associated with Conservation Modernization (ConMod) investments.*

A. ConMod conservation investments were made to aluminum reduction plants in the region to reduce the amount of electricity consumed in the production of aluminum. Adjustments for conservation savings associated with ConMod investments were already subtracted out of the savings reported in the Red Book for FYs 1988-1999. The savings were subtracted out of the Red Book's totals because the loads associated with the aluminum reduction industry that undertook the ConMod investments are for the most part no longer operating. Since one of the Red Book's objectives is to account for BPA's conservation spending, the costs of the ConMod investments were retained in the Red Book. ConMod costs totaling $48.1 million associated with ConMod investments for FYs 1988-1999 were subtracted from the costs of conservation investments for those years in determining resource stack costs.

Q. *Please explain adjustments that were made to the Red Book's conservation savings associated with Model Building Code conservation investments.*

A. Building code savings totaling 21.1 aMW for FYs 2002-2004 were subtracted from the Red Book amounts. The benefits from earlier investments (FY 1983-1999) to promote model energy code standards had largely been achieved by FY 2002. To objectively state the amount of conservation savings for FYs 2002-2004 it was necessary to reduce the building code savings contained in the conservation savings totals for those years.

Q. *Please explain the adjustments that were made to the Red Book and BPA program budgets for conservation savings and costs associated with Conservation and Renewables Discount (C&RD) conservation investments for FYs 2002-2006.*

A. Conservation savings totaling 55.2 aMW and related expenditures totaling $196.0 million associated with C&RD investments for FYs 2002-2006 were removed from the resource stack. During these years, C&RD costs were not included in BPA's revenue requirement in determining "base" rate levels for FYs 2002-2006. They were added after the determination of base rates and were credited back to customers as credits on their power bills in return for agreeing to invest the money in conservation efforts or renewable resources The load forecast for the FY 2002 – FY 2006 rate period did not include conservation savings for C&RD investments made in that time period. See Estvelt *et al* WP-02-E-BPA-33. The controls and compliance efforts surrounding the achievement of conservation savings during FYs 2002-2006 were less robust than past practices, making the savings from these expenditures less assured. In addition, the majority of the utilities participating in this program were non-load-following customers for which the Administrator's load obligations were not reduced. For these reasons all of the savings and expenditures associated with C&RD for FYs 2002-2006 were subtracted from the resource stack for those years.

Q. Please explain the adjustments that were made to the Red Book's and BPA's program budgets for conservation savings and costs associated with the Conservation Rate Credit (CRC) conservation investments for FYs 2007-2013. A.

The CRC is the replacement program to the C&RD program included in the WP-02 rates. Conservation savings totaling 84 aMW associated with the 140 aMW total savings from the CRC investments for FYs FY 2007-2013 were removed from resource stack totals. However, all of the costs associated with the CRC program for the FYs 2007-2013 were included in the resource stack.

The reason for removing 84 aMW of savings is based on the fact that these savings occur in the service territories of BPA's non-load-following customers (customers purchasing the Slice or block power products). Because there is no reduction in the amount of power that these customers are entitled to purchase under their take-or-pay contracts, there is no reduction in the Administrator's load obligations associated with the CRC savings that occur in their service territories.

The reason for including all of the costs associated with the CRC conservation program in the resource stack is that, unlike the FY 2002-2006 time period where the C&RD costs were not included in the WP-02 revenue requirement, the WP-07 revenue requirement includes CRC costs. The rates charged all BPA customers include CRC costs. It would be inequitable and infeasible to conduct a conservation program where only load-following (Full Service and Actual Partial Service) customers were eligible to participate. In order to achieve the conservation savings that occur in the service territories of Full Service and Actual Partial Service customers, BPA also needs to undertake the CRC program for all customers who pay for CRC costs.

Q. Please explain the adjustments that were made to the Red Book's and BPA's conservation program savings and costs associated with Market Transformation conservation investments.

A. Conservation savings totaling 106.4 aMW associated with the 152.0 of total savings from Market Transformation investments occurring during the years FY 1999-2013 were removed from resource stack totals. Market Transformation savings in the Red Book and BPA's program budgets include regional conservation savings associated with loads that are not served by BPA. Savings amounts contained in the resource stack have to be able to reduce the loads that BPA faces in the 7(b)(2) Case; thus, it was necessary to subtract these savings from the resource stack.

The total expenditures associated with Market Transformation investments were included in the resource stack's costs, because BPA found it necessary to fund approximately fifty-percent of the regional market transformation effort to realize the benefits that were just attributable to the loads that BPA serves. Market Transformation benefits/savings, by their distributed nature, cannot be restricted to BPA's service area. BPA costs for market transformation activities are proportional to benefits accrued in its service area.

Q. Please summarize the total amount of conservation savings and related expenditures that were removed from the resource stack.

A. Adjustments that reduced conservation savings available to the resource stack totaled 101.9

aMW for the years 1982-2004. Adjustments that reduced the projected conservation savings associated with BPA's program plans and budgets for the years 2005-2013 totaled 164.8 aMW, for a combined total of 266.7 aMW of savings. The reduction in conservation costs contained in the resource stack associated with these resource reductions totaled $244.4 million. The documentation for the conservation savings and the related costs can be found in the Section 7(b)(2) Rate Test Study Documentation, WP-07-E-BPA-06A, Appendix D.

Q. Please describe how conservation resource acquisitions are modeled in conducting the 7(b)(2) rate test.

A. Conservation resources, along with other resources contained in the resource stack, are selected to meet the additional loads in the 7(b)(2) Case based on a least-cost ranking. Unlike other resources in the resource stack, conservation resources reduce the amount of loads served in the 7(b)(2) Case, so there are fewer loads to distribute the 7(b)(2) Case costs over. Conservation costs for a particular year's conservation investments reflect the actual costs associated with the conservation investments for that year. These costs are shown in the resource stack in real 1980 dollars. When selected from the resource stack, an inflation adjustment is performed to change the real 1980 dollars to nominal dollars. That portion of a year's conservation investment that is denoted as annual O&M (first year conservation expense) in the resource stack is expensed only in the first year that the conservation resource is chosen from the resource stack. The annual debt service costs associated with financing the capitalized portion of a year's conservation investments are included in the revenue requirement for the first year the conservation resource is selected and for all subsequent years of the study period. The capital costs associated with a particular year's investments are financed over a period of 20 years for conservation investments pertaining to the years 1982-2001, and over a period of 15 years for conservation investments pertaining to the years 2002-2013. These financing periods match the composite useful life of the conservation investments undertaken for those years as determined by the Northwest Power Planning

Council's (NWPPC) conservation resource analysis. The resource stack denotes the interest rate used for conservation capitalized/financed over 20 and 15 years as 5.34% and 5.09%, as outlined in Section 5 above. The debt service calculation assumes a level payment amount (mortgage based).

Q. What assumptions were used regarding the capitalization and financing of conservation in the Program Case, and how are those assumptions different than those used in the 7(b)(2)Case?

A. The Program Case reflects BPA's actual accounting and financing policies. These policies have to support debt management considerations (debt optimization with Energy Northwest (ENW)), capital investment priorities, and other dynamic business management issues that BPA faces in operating and maintaining the FCRPS for the region. In the spring of 2005, BPA adopted a conservation policy of capitalizing and amortizing conservation investments over a period of five-years. During FY 1995-2005, BPA issued $452 million in conservation bonds with varying terms, ranging from 3 to 20 years with a weighted average interest rate of 5.89%. In the 2007 Program Case, BPA is projecting that it will issue $257 million for conservation investments using five-year bonds over the years 2007-2013 with a weighted average interest rate of 6.18%.

In the 7(b)(2) Case, conservation financing is based on the assumption that BPA would acquire conservation savings from a JOA (*see* Section 7(b)(2) Rate Test Study Documentation, WP-07-E-BPA-06A, Appendix A) that is formed by the preference customers. It is assumed that the JOA would have adopted a conservation capitalization/amortization policy that was based on the useful life of conservation investments based on the NWPPC estimates. The NWPPC's estimates for the average useful life of conservation measures was 20 years for investments that occurred during 1982-2001 and 15 years for investments made after 2001. PFM's financing analysis projected that the JOA would have obtained financing at a cost of 5.34% and 5.09% for 20- and 15-year maturities as outlined in Section 5 above. The 7(b)(2) Case uses the above interest rates in calculating the debt service expense to be included in the revenue requirements for conservation investments selected from the resource stack. The interest rate differential between the Program Case and the 7(b)(2) Case reflects the difference in capitalization policies and financing assumptions used in the two cases.

Section 9. DSI Reserve Benefits

Q. Please describe the DSI reserve benefits used in the 7(b)(2) rate test.

A. For the WP-07 rate period, no BPA sales to the DSIs are forecast in the Program Case, and thus no DSI loads are present in the 7(b)(2) Case. *See* Gustafson *et al.*, WP-07-E-BPA-18. Because no BPA sales to the DSIs are forecast, the reserve benefits provided under the Northwest Power Act are also forecast to be zero.

Section 10. Summary of 7(b)(2) Rate Test

Q. What are the results of BPA's 7(b)(2) rate test?

A. The 7(b)(2) rate test triggers by 0.7 and 7(b)(2) customers are eligible for rate protection of approximately $40 million per year.

Q. Does this conclude your testimony?

A. Yes.

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